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16. ABSTRACT

The proceedings document presentations made at the EPA/Industry Forum on Coal Liquefaction, October 23 and 24, 1979, in Chicago. The forum brought together representatives of government and industry with the goal of sharing information and increasing cooperation between the two groups. Following an overview of EPA's activities in the area of synthetic fuels, standards-setting procedures, activities, and plans relating to coal liquefaction were discussed for air emissions, solid wastes, and liquid effluents. EPA permit procedures were summarized for coal liquefaction plants. EPA's research and development activities in coal liquefaction were described, as were plans and activities of EPA's Industrial Environmental Research Laboratory (RTP) in coal liquefaction. State government participation in coal liquefaction development was discussed for Kentucky and Illinois. Industry plans in the area of coal liquefaction were presented by representatives of several firms actively involved in development and use of the technology: Exxon Research and Engineering Co., Ralph M. Parsons Co., Hydrocarbon Research, Inc., Mobil Research and Development Corp., Texas Eastern Corp., and Fluor Corp.

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ABSTRACT

The EPA/Industry Forum on Coal Liquefaction was held on October 23 and 24, 1979, in Chicago. The forum brought together representatives of government and industry with the goal of sharing information and increasing cooperation between the two groups.

The meeting was opened by John McGuire, Administrator for EPA Region V, who welcomed the participants and outlined the purpose of the meeting. Frank Princiotta, Director of EPA's Energy Processes Division, presented an overview of EPA's activities in the area of synthetic fuels. Standard-setting procedures, activities, and plans relating to coal liquefaction were discussed by discharge medium, as follows: air emissions, Jack Farmer, EPA Emission Standards and Engineering Divison; solid wastes, Yvonne Garbe, EPA Hazardous Waste Management Division; and liquid effluents, William Telliard, EPA Effluent Guidelines Division. Terry Thoem, Director of EPA Region VIII Energy Policy Coordination Office, summarized EPA permit procedures for coal liquefaction facilities.

EPA's research and development activities in coal liquefaction were described by Norbert Jaworski, Deputy Director of EPA's Industrial Environmental Research Laboratory in Research Triangle Park, North Carolina. Robert Hangebrauck, Director of the Energy Assessment and Control Division at Research Triangle Park, discussed the plans and activities of this division in coal liquefaction.

State government participation in coal liquefaction development was discussed by two speakers: Harry Enoch, Assistant Director of Technology Assessment, Kentucky Department of Energy; and Daniel Pierce, Chairman of the Illinois Energy Resources Commission.

Industry plans in the area of coal liquefaction were presented by representatives of several firms actively involved in development and use of the technology: Robert C. Green, Exxon Research and Engineering Co.; James B. O'Hara, Ralph M. Parsons Co.; Richard Eccles, Hydrocarbon Research, Inc.; Vernon W. Weekman, Mobil Research and Development Corp.; Barnet Groten, Texas Eastern Corp.; and Sid Thomson, Fluor Corp.

The forum was highlighted by the kind of frank interchange that will lead to closer cooperation in meeting the President's goals for the development of synthetic fuels.

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INTRODUCTION/EXECUTIVE OVERVIEW
EPA/INDUSTRY FORUM ON
COAL LIQUEFACTION
Chicago, Illinois
October 23 and 24, 1979

Plans and activities in the development of coal liquefaction were discussed by the nearly 50 participants in the forum, which included representatives of the U.S. Environmental Protection Agency, the U.S. Department of Energy, several state governments, and industry. EPA speakers discussed the Agency synfuels activities, including research and development, environmental assessment, standard setting, and permitting. Seven industry speakers outlined their firms' plans and activities in coal liquefaction. In addition, two speakers discussed state government experience in planning for coal liquefaction facilities.

Summaries of the speakers' remarks follow.

JOHN McGUIRE, REGIONAL ADMINISTRATOR, EPA REGION V

McGuire welcomed the participants and discussed EPA's role in meeting the President's goal of lessening our national dependence on foreign oil. He stressed the importance of cooperation between EPA and industry in meeting national energy and environmental goals.

FRANK PRINCIOTTA, DIRECTOR, ENERGY PROCESSES DIVISION, EPA-WASHINGTON

Princiotta summarized the President's program to halve oil imports by 1990 and discussed the status of legislation to implement the program. The roles of the Energy Security Corporation and the Energy Mobilization Board were reviewed, as were EPA projections of U.S. fossil energy resource requirements and energy flows in 1990.

He explained how EPA's research and regulatory programs fit in with the synthetic fuel program, noting that the types and quantities of synfuel pollutants differ substantially from the kind of pollutants with which EPA is familiar. Intelligently planned and sited commercial facilities, he stressed, can be built at acceptable cost and still meet all current environmental regulations.

Princiotta discussed the development of EPA's regulatory strategy for the synthetic fuel industry. Its major goal will be to promote the incorporation of best available controls for all major facilities. It is expected that legally binding regulations will not be promulgated before 1983.

EPA's research program goals and funding levels were outlined, and major findings of the program were summarized. Preliminary indications are that control technology for methanation is probably effective, and will increase the capital cost of a Lurgi gasification plant by 5 percent and operating costs by 10 percent. He stressed that EPA's job is to avoid discouraging commercialization of synthetic fuel technology, but at the same time to protect the environment.

JACK FARMER, CHIEF, CPB, INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY, EPA-RTP

Farmer discussed standard-setting procedures, activities, and plans relating to air emissions from coal liquefaction. He reviewed the function of the New Source Performance Standard, which requires the application of the best system of emission reductions, taking into account cost, health, environmental, and energy requirements. To date, EPA has published New Source Performance Standards for 27 source categories and has proposed standards for four additional categories. During 1980, plans call for proposing standards for an additional 15 source categories and issuing final standards for six categories.

Farmer outlined the three phases of standards development: first, a short-term study characterizing the source category to determine whether a standard is appropriate; second, data gathering through literature searches and personal contact; and third, analysis and evaluation of the data for development of a draft or recommended standard. Procedures for review of recommended standards, both within and outside EPA, were summarized.

No air standards development projects have yet been initiated for synthetic fuel processes, although Farmer said that a low-Btu gasification project is under serious consideration.

YVONNE GARBE, ENVIRONMENTAL ENGINEER, HAZARDOUS AND INDUSTRIAL WASTE DIVISION, EPA-WASHINGTON

Garbe summarized EPA's standard-setting procedures, activities, and plans relating to solid wastes from coal liquefaction. At present, the Hazardous and Industrial Waste Division is responding to comments generated by publication of proposed regulations to control hazardous wastes.

She explained the structure of the hazardous waste program, which responds to Subtitle C of the Resource Conservation and Recovery Act. Subtitle C provides a cradle-to-grave management system for hazardous waste. Non-hazardous wastes are addressed in Subtitle D standards.

EPA has established a special waste category for high-volume wastes whose composition, characteristics, and degree of hazard are not readily known but which are believed to have a low risk. Examples cited by Garbe of wastes in this category are metal mining wastes, gas and oil drilling muds and oil production brines, and cement kiln dust. She noted that the open comment period on the proposed regulations had produced several suggestions to include coal liquefaction waste (slag, char ash, and sludge) in this special category. These suggestions, she said, are receiving serious consideration.

NORBERT JAWORSKI, DEPUTY DIRECTOR, INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY, EPA-RTP

Jaworski presented an overview of R&D activities in coal liquefaction. He discussed the laboratory's two major activities: environmental assessment and control technology development. The energy R&D program covers flue gas desulfurization technology, both regenerable and nonregenerable systems, and the use of baghouses and precipitators for particulate control of conventional combustion systems. Other programs are investigating NO_x control and fluidized bed technology.

He discussed the importance of developing procedures and protocols to assure the consistency of data analysis and chemical analysis performed by outside contractors.

The Laboratory's role in support of EPA is in problem definition - predicting, for instance, the potential harmful impact of a synfuels program. While early efforts focused on the environmental assessment methodology, the current emphasis is dictated by the pollution control guidance documents. The laboratory is heavily involved in the costs and engineering aspects of environmental control systems.

ROBERT HANGEBRAUCK, DIRECTOR, ENERGY ASSESSMENT AND CONTROL DIVISION, INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY, EPA-RTP

Hangebrauck discussed EPA's R&D environmental assessment and control technology plans in coal liquefaction. He outlined the work of the agency's major contractors in coal liquefaction - TRW, Hittman Associates, and Radian - and discussed the status of relevant field studies.

In addition, EPA also supports the activities of the Synfuels Environmental Center, a group of universities and the Research Triangle Institute, located near the laboratory in North Carolina. Their efforts are dedicated to the creation of a center of expertise to work toward some environmental understanding in this area. The Center is engaged in pollutant screening studies, in investigating options for gas and wastewater clean-up and solid waste disposal, and in combustion modifications testing.

Hangebrauck discussed the reports generated by the laboratory, including the standard support plan, source test and evaluation report, environmental assessment report, and pollution control guidance document.

The basic components of the environmental assessment methodology were outlined, as was EPA's phased approach to sampling and analysis. Hangebrauck illustrated these EPA methods using a gasification case study.

ROBERT GREEN, SENIOR ENGINEERING ASSOCIATE, EXXON RESEARCH AND ENGINEERING COMPANY

Green described the development status of the Exxon Donor Solvent (EDS) coal liquefaction process. Currently, the results of bench-scale research, operation of small pilot units, and engineering design and technology studies are being integrated with the operation of a 250 ton-per-day pilot plant, which has a planned completion date of spring 1980. Key objectives of pilot plant operation are demonstration of operability, design data acquisition, product yield and quality confirmation, and testing and production of feeds for demonstration of environmental coals.

Green summarized process yields and expected environmental effects of the process. Obstacles to commercialization were discussed, including the current price of hydrocarbon liquids and environmental and permitting difficulties.

JAMES B. O'HARA, MANAGER, ENERGY DEPARTMENT, RALPH M. PARSONS COMPANY

O'Hara outlined the activities of the Ralph M. Parsons Company in the design, engineering, procurement, and construction of coal liquefaction facilities. The firm does not plan to offer a proprietary liquefaction process, but rather offers familiarity with the major technologies.

He summarized Parsons experience in construction management and discussed the company's position in sulfur systems engineering. Parsons has designed 80 percent of the free world's sulfur recovery plant capacity. The Claus unit has been used extensively with streams containing 20 to 30 percent hydrogen sulfide or even less. Parsons has recently built modified sulfur-burning Claus units that can handle streams containing 7 to 8 percent hydrogen sulfide. While at present they would recommend use of the Stretford process for streams containing less than 5 percent hydrogen sulfide, Parsons is developing a new process to handle feeds as low as 1 percent.

Parsons has developed conceptual designs for each of the generic types of coal liquefaction plants, including direct liquefaction, indirect liquefaction, and pyrolysis. He discussed treatment procedures for these plants, and noted that where costs of conceptual coal liquefaction environmental facilities have been estimated, they have been in the same percentage range as is encountered for grass-roots oil refineries -- 10 to 15 percent.

D.M. JACKSON, MANAGER, PROGRAM DEVELOPMENT, GULF MINERAL RESOURCES COMPANY

Jackson outlined the development status of SRC-II, which is being tested at the SRC pilot plant in Fort Lewis, Washington. The SRC fuel oil is envisioned for use in utility-industrial boilers, combustion turbines, and medium-speed diesels.

He also discussed the results of a boiler test performed with 5,000 barrels of the broad-range fuel at a Consolidated Edison generating station in Manhattan. The test indicated acceptable levels of NO_x, particulates, and other emissions.

The results of a Phase Zero assessment of SRC-I and -II were also discussed. The assessment, which covered design, environmental assessment, site acquisition, and market assessment of products, suggested a substantial and continuing economic attractiveness, at least in the utility sector, for a liquid fuel derived from coal. The study also revealed that maintaining and rehabilitating existing oil-fired capacity is far more attractive than abandoning it and replacing it with new equipment, generally base-load direct coal-fired. He noted that the indirect price of oil, at which utilities will abandon their oil-fired equipment and build coal-fired, can reach as high as $50 a barrel, indicating the attractiveness of coal-oil liquids in the utility sector.

Jackson discussed Gulf's involvement as a prime contractor and financial positioner in a program to design, build, and operate an SRC-II demonstration module.

HARRY ENOCH, ASSISTANT DIRECTOR, TECHNOLOGY ASSESSMENT, KENTUCKY CENTER FOR ENERGY RESEARCH

Enoch presented an overview of the State of Kentucky's activities in the area of coal conversion. Demonstration projects currently underway include the H-Coal pilot plant in Catlettsburg, Kentucky; an SRC-I demonstration module in Newman, Kentucky; and a commercial-size ammonia plant using coal as its feedstock for hydrogen production. The scope of the latter project has been changed to production of methanol from coal syngas and methanol to gasoline, using the Mobil-M process. This project is located in Baskett, Kentucky.

The State of Kentucky is conducting background studies to find suitable sites for large coal conversion facilities. Potential sites are identified and catalogued based on several general criteria, including availability of land, water, coal, and transportation. The state will begin soon to investigate sites that are out of the coalfields and off rivers.

Enoch challenged the conclusions of a DOE report, Environmental Analyses of Synthetic Liquid Fuels, which identified no adequate sites for synfuels plants in the State of Kentucky.

WILLIAM TELLIARD, BRANCH CHIEF, EFFLUENT GUIDELINES DIVISION, EPA-WASHINGTON

Telliard discussed standard-setting procedures, activities, and plans relating to liquid effluents from coal liquefaction. The Effluent Guidelines Division is developing a program that will lead to the creation of New Source Performance Standards for the synthetic fuel industry. Their priorities will be set by those industries with the shortest schedule before coming on-line; that is, those with an immediate need for a permit to operate. They are discussing efforts in gasohol and gasification, and plan to address the 65 priority pollutant groups. Present estimates call for proposed regulations for liquefaction to be issued in 1983.

He stressed the need for treatability information, which, in the absence of a regulation, gives the permit writer source information with which to work.

Telliard also briefly outlined the major steps involved in the development of effluent guidelines: waste characterization, alternative treatment technologies, economics, and engineering costing.

TERRY THOEM, DIRECTOR, ENERGY POLICY COORDINATION OFFICE, EPA-REGION VIII

Thoem discussed permitting procedures as they relate to coal liquefaction facilities. He noted that the intent of most federal environmental legislation is to delegate regulatory programs to the states. Once a program is delegated to a state, EPA assumes an oversight role, with the state issuing the permit and EPA providing technical assistance if needed.

Thoem summarized the various tools used in regulation of air quality, including New Source Performance Standards, State Implementation Plans, Prevention of Significant Deterioration permits, the concept of Best Available Control Technology, ambient increments, and visibility regulations. He also described mechanisms for water quality and solid waste control, including the provisions of the Clean Water Act, the Safe Drinking Water Act, the Toxic Substances Control Act, the Solid Waste Act, and the Resource Conservation and Recovery Act.

He noted that EPA is investigating ways to simplify the permit process, including consolidating permit requirements and streamlining the application process. He said that EPA is committed to processing all energy facility permit applications in six months.

RICHARD ECCLES, VICE PRESIDENT, HYDROCARBON RESEARCH, INC.

Eccles described the activities of Hydrocarbon Research, which does not commercialize technology, but rather develops it and makes it available, performing front-end activities such as laboratory work, planning, and early design. HRI coal liquefaction involvement described by Eccles includes a 3.5 ton-a-day process development unit used to simulate the operation of the Catlettsburg H-Coal pilot plant, a process development unit at the Wilsonville SRC facility, participation in the second-generation gasification project of the Illinois Coal Gasification Group, and development of a new process called coal/oil integrated liquefaction (COIL), an ebullated bed with coal and oil fed as a mixture.

VERNON W. WEEKMAN, JR., MANAGER, PROCESS R&D, MOBIL OIL CORPORATION

Weekman discussed the conversion of methanol to gasoline. Mobil is negotiating with the Government of New Zealand for the development of a fixed-bed unit for the conversion of natural gas. The unit will use a unique new zeolite catalyst developed by Mobil.

Mobil is also working on a fluid-bed version and has completed a four barrel-a-day pilot plant with DOE. They are currently negotiating with DOE, the Government of the German Federal Republic, and two German companies for a scale-up to 100 barrels a day. The gasoline produced in this process is environmentally cleaner than conventional gasoline, according to Weekman, who said that process waste streams are comparable to those of a refinery.

BARNET GROTEN, DIRECTOR, RESEARCH AND TECHNOLOGY, TEXAS EASTERN CORPORATION

Groten presented a summary of Texas Eastern's energy activities, which include interstate gas and liquid products transmission systems, and oil and gas production. Research and development activities include heavy oil production, secondary and tertiary recovery of petroleum from conventional reservoirs, development of unconventional gas sources, and investigations in synthetic fuels technology.

He discussed environmental aspects of the three processes that are ready for commercialization: Lurgi gasification followed by methanation to SNG, production of methanol, and Fischer-Tropsch to liquid fuels.

Evaluation of Lurgi gasification, in the form of Environmental Impact Statements, is continuing. The environmental aspects of the methanol module in a coal-to-methanol plant are as well understood as those of any methanol plant based on natural gas reforming.

Texas Eastern has recently contracted with SASOL, Limited, to evaluate the cost of building a Fischer-Tropsch plant at a U.S. site, employing U.S. coals, and conforming with U.S. environmental requirements. South Africa's 20 years of operational experience with this process has created a thorough understanding of its environmental effects.

Groten noted an important distinction between the abovementioned indirect processes and the direct technologies, which involve a synthetic crude product that is far less fully characterized and a process that has reached neither the scale nor the endurance level of any of the indirects.

SID THOMSON, MANAGER, ENVIRONMENTAL ENGINEERING, FLUOR ENGINEERING AND CONSTRUCTION, INC.

Thomson characterized Fluor's activities in the engineering and construction of environmentally acceptable coal liquefaction plants. Fluor is participating in the SASOL projects with the government of South Africa. Through their experience with SASOL and other projects, they have found that environmental impacts resulting from the indirect processing of coal to liquids by the Fischer-Tropsch process can be mitigated by proper design based on present knowledge.

He described the process and its products in detail, using as an example the WESCO Project, for which an uncontested Environmental Impact Statement was issued and which received a permit to operate and construct from the State of New Mexico.

DANIEL M. PIERCE, CHAIRMAN, ILLINOIS ENERGY RESOURCES COMMISSION

Pierce detailed the activities of the State of Illinois in synthetic fuels, including a fluidized-bed project with Combustion Engineering at Great Lakes Naval Training Station. The state has been unsuccessful in attracting and retaining federal support for other projects.

He discussed the impact of the Administration's energy program on synfuels development, noting that we may see some shortcuts taken in environmental regulation.

Illinois' qualifications as a site for gasification and liquefaction plants were outlined. Pierce discussed a coal gasification project being developed by Allis-Chalmers. Illinois has authorized $18 million in coal development funds for this kiln gas project at the Wood River Plant. The Illinois Power Company and a national consortium of 15 to 20 electric utilities are helping to fund the project. Its long-term objective is to make a gasifier out of the kilns that are now used in iron ore work and to produce a low-Btu natural gas to be fed into Illinois Power's existing steam boiler plant at Wood River.

Pierce also outlined plans for the Cumberland Energy Plex, a total-concept energy facility planned for southeastern Illinois. Plans call for the construction of four new coal mines, supplying 4,000 tons of coal per day to power plants. The Energy Plex would also produce synthetic natural gas and ammonia.

Opening Remarks: John McGuire, Region V, EPA

Good morning, ladies and gentlemen. My name is John McGuire. I am the Regional Administrator for Region V, the Midwest Region of U.S. EPA.

I want to welcome all of you to this U.S. EPA/Industry Forum on Coal Liquefaction. This is a subject foremost in the minds of our nation, especially in light of the President's emphasis on developing a capability for energy independence from the OPEC nations and his orders to cut oil imports.

I am pleased to see the nationwide representation from industry, from other federal agencies, from EPA laboratories and other EPA regions, and from universities and research centers. This task will require a major effort from all of us and a dedication to complete cooperation to accomplish our nation's goals.

It is not only desirable but quite logical that this forum on utilization of coal should be held here. As many of you know, the coal resources in Illinois alone collectively outweigh the energy resources of the OPEC countries. Utilizing coal to the maximum extent is what the President had in mind when he spoke to the nation several weeks ago. He set an oil import limit at the 1977 import level. That level is to be cut by half by the end of the next decade, a savings of over 4.5 million barrels of imported oil per day.

The President further stated, "To give us energy security I am asking for the most massive peacetime commitment of funds and resources in our nation's history to develop our own alternative sources of fuels, namely, coal, oil shale, from plant products for gasohol, from unconventional gas, and from the sun."

The President proposed the synthetic fuel initiative with emphasis on coal liquefaction. His synfuel plan proposes 2 million barrels per day capacity by 1990, including 1.5 million barrels from coal liquefaction.

In order for EPA to set realistic, timely levels of emissions for effluent standards in parallel with commercialization, and in order for industry to incorporate adequate control technology as early as possible, it is necessary for both industry and EPA to understand each other's plans and procedures. Only through cooperation can we meet both our nation's energy and environmental goals.

My colleagues from the Office of Research and Development, EPA, Washington, have planned this coal liquefaction forum today as a first step to accomplish these goals and to promote from the start a mutual understanding between industry and government of each other's interests and problem areas.

Frank Princiotta of our Office of Research and Development will provide additional background and history on synfuels, as those processes are known today. He will also elaborate on the President's program for synfuel development and on EPA's role in regulatory research strategy.

Overview of EPA Synfuels Activities: Frank Princiotta, Office of Research and Development, EPA

Thank you very much, John. I appreciate that. I appreciate these facilities as well. Just about the right room, I think, for this particular crowd.

I would like to briefly discuss why we are here, discuss the President's proposed energy program, and indicate the major thrust that we are making in EPA toward upgrading both our research program and our regulatory program relating to synthetic fuels.

Let me first summarize some of the major elements of the President's program. On July 16, 1979, the President in his televised address proposed a major import reduction program aimed at cutting back our oil imports by half in 1990. Currently, we import roughly 9 million barrels a day of oil. His goal is to save 4.5 million barrels a day by 1990.

I think most relevant to this particular meeting is the 2.5 million barrels a day that he was hoping to save through the use of synthetic fuels and unconventional natural gas production initiative. Additional savings are as follows: heavy oil production in the West, particularly California, .5 million barrels a day; reduction in oil use in utilities, .75 million barrels a day; and conservation in residential and mass transit auto efficiency areas, another .75 million barrels a day.

The first number, which is the critical one for us, was to be expended through the Energy Security Corporation that the President proposed. This, of course, requires legislation and the Congress is now deliberating on these proposals. The corporation would provide the incentive for this kind of synfuel production. In addition to the traditional synthetic fuel liquefaction, it would also include gasification, ethanol and methanol from biomass, and unconventional natural gas, which of course is not a synthetic fuel but is deemed to be available if one provides sufficient incentive.

This corporation, proposed to be independent and government sponsored, would have a seven-person board. The Departments of Energy and Treasury would be represented and one other agency as well. The President proposed that $88 billion would be needed to fund the security corporation over its 10-year life. The funds would be obtained from the windfall profits tax, which is also pending in Congress.

The current incentives that were proposed included GOGOs (government-owned, government-operated); government-owned, contractor-operated; price guarantees; direct loans; and loan guarantees. It is essentially at the discretion of the security corporation to decide just how it should provide the appropriate incentive for a particular technology.

As you may know, there have been some changes in the program on the Hill. The Senate has recently passed a bill which has some important changes. For one thing, the goal of 2.5 million barrels a day by 1990 is now reduced to 1.7 million barrels by 1995. Instead of $88 billion being made available to this corporation up front, the new number is on the order of $20 billion as kind of a first installment, with subsequent installments starting a couple of years later. By and large, however, I think they retain much of the same philosophy of the President's proposal. The situation on the House side is not nearly as clear. I am sure we are several months away from funded legislation in that area.

The funding source is critical because this corporation and the incentives that it will provide will not happen unless the resources are made available. The President proposed to obtain this $88 billion, and now the reduced figure, from the energy security fund, which, of course, results from profits associated with oil decontrol, the so-called windfall profits tax.

The present program, his windfall profits tax program, is having some rough going on the Hill right now. The House has passed a bill quite similar to the President's proposal but the Senate Finance Committee has a much reduced windfall profits tax. Deliberations will continue. I suspect the big profit that Exxon reported just yesterday might have a little something to do with the ultimate determination as to just how big the windfall profits tax will be.

It's important to note that the President's program is dependent on some kind of receipts associated with windfall profits that are not already earmarked for some other use.

Another major part of the President's program relating to synthetic fuels and therefore liquefaction is his Energy Mobilization Board. This is being greeted with more enthusiasm by the Hill, which is consistent with this anti-regulatory mood that we are in. The purpose of the Mobilization Board is to expedite the processing of synthetic fuel and other major non-nuclear facilities through regulatory permitting operations. Again, legislation is needed. The proposed three-member board would report directly to the President and would relate to non-nuclear energy facilities. Its goal would be to establish bonding schedules and to make siting decisions where the appropriate regulatory agency, be it state, federal, or local, did not step in and do what had to be done. Perhaps the most controversial feature of the Mobilization Board would be the authority to waive procedural requirements.

One of the more prominent bills in the House right now calls not only for the authority to waive procedural laws and regulations but substantive regulations as well. While the definition is not clear, it appears that in the extreme many of the environmental regulations could be waived. That's causing very active debate in the House, partcularly right now. The Administration has not been overly clear about just how far it wants to go in providing the authority to waive legislative requirements. The Mobilization Board as proposed would only be subject to review and reversal by the Court of Appeals or ultimately a Presidential veto. Some of the House versions name the Congress as one of the vetoing parties.

Finally, I am sure you have your own opinion on just where this whole synthetic fuel initiative is going. I will give you mine, for what it's worth. I think within two or three months we will have major breakthrough legislation for a massive synthetic fuels program. I think it will not be on quite the scale the President initially proposed. I think the number will be more like 1.5 or 2 million barrels a day in 1995 as opposed to 1990, but I'm sure that those of you in the synthetic fuel business will agree that these are still very ambitious goals. A goal of 2 million barrels a day would still require forty 50,000 barrel-a-day facilities, so we are talking about massive commitments to a new, relatively untried, synthetic fuels industry.

Let me briefly discuss the DOE numbers that were prepared at the same time the President proposed this program. This is their breakdown of the 2.5 million barrels a day in the President's original program. They thought that the contribution from coal liquids and coal gases would be from 1 to 1.5 million barrels a day. In fact, the bulk of that would be from coal liquids. A further breakdown of that would look something like this: 1 million barrels a day from indirect coal liquefaction, about 300,000 barrels a day from direct coal liquefaction processes, and the remaining 200,000 barrels a day from coal gasification. Oil shale was talked about at a 400,000 barrel-a-day level, alcohols at a 100,000 barrel-a-day level, and the swing item of unconventional natural gas ran between .5 and 1 million barrels a day.

Of course, this is strictly speculation. The Security Corporation would have discretion to push for one technology above the other, but our major problem appears to be in the liquid fuel area so that coal liquids and shale oil will be predominant in any synthetic fuel initiative.

I would like to discuss some EPA projections on energy futures. I am sure those of you who work for oil companies make your own projections. I don't claim ours are any better or worse than anybody else's but I think they give some indication of the future, particularly with regard to synthetic fuels.

Our predictions of the total U.S. fossil energy resource requirements in 1990 from coal, natural gas, and oil shale are compatible with the President's original program, which means they are already a little bit out of date because the synthetic fuel goals have been reduced somewhat. I think most studies generally agree with these rough trends, namely that coal use will increase drastically over the next 25 years. We see almost a tripling in coal use, despite the fact that we are running at capacity now.

The liquid fuel component is critical in our desire to be free of dependence on Middle East oil. This projection is equivalent to the roughly 1.5 or 2 million barrel-a-day goal the President originally set for liquid fuels and we essentially saw a projected doubling by the year 2000. Of course, our crystal ball gets awfully cloudy into the year 2000.

Moving to oil shale, we see the 400,000 barrel-a-day number, which is about .8 quads. The maximum size of the oil shale industry is perhaps 1 to 1.5 million barrels a day.

A particularly relevant number is the fraction of the domestic oil that we use that is imported. The size of this fraction is dependent upon the liquids that we get from other sources, namely coal, coal liquefaction, and oil shale. If we are too optimistic in our trends and projections with regard to synthetic liquids and oil shale liquids, I think what clearly will happen, everything else being equal, is that these numbers will tend to grow. Our reliance on imported oil will remain roughly comparable to what it is now, perhaps even grow. If one looks at just the domestic fraction or portion of energy resource requirements, this kind of pattern is apparent. Again in the case of coal we see the same numbers because essentially all the coal is domestic coal.

Eastern underground mining is projected to grow substantially, as is Western strip mining. Eastern strip mining is not projected to grow very much.

In oil, we project the major growth areas will be offshore oil, heavy oil, and, to a lesser extent, the current onshore oil capabilities. We show primarily surface processing of oil shale in in-situ processing coming on later in this century.

I think it is relevant to this meeting to discuss just how this coal will be used. We will see it used heavily by electric utilities, replacing to a large extent our reliance on natural gas and heavy oils for electricity production. We will also see it being used in the industrial sector.

Again we see the bulk of the action in the coal liquefaction area because of the liquid fuel problem. Again we are very speculative as to whether or not we can have on the order of 3.5 or 3 million barrels a day of synthetic fuel capacity by the year 2000. Some studies suggest this is feasible. In any event, it's certainly very ambitious.

So what will our energy flow system look like in the year 1990? I hope I won't dazzle you with too many colors here but this is essentially a projection of the major energy flows in the year 1990. We don't have all the major flows. You don't see hydroelectric, solar, geothermal, or some of the non-fossil energy fuel supplies.

One can't look at the energy situation as requiring energy for various purposes. We have certain devices that require electricity for operation, air conditioning, light bulbs, industrial machinery, and water. Well, they just rely on electricity. We will obviously have to supply that through electricity production, and we see that being primarily the domain of nuclear power and coal.

Figure 1 charts energy flow for the United States in 1990. We showed a coal cleaning mode, and then coal-fired power plants and to a lesser extent we see oil being used in power plants from traditional oil supplies as well as oil shale and liquefied coal products. But in our view of the world, and I think it's compatible with DOE's view of the world, we will see very little in the way of oil-fired power plants; electricity will be primarily produced via nuclear and coal-fired power plants.

But in the critical liquid fuels sector, the most important liquid fuel utilization devices are the transportation devices. Right now we cannot drive our automobiles or airplanes or almost any other transportation vehicle without liquid fuels.

You will note we did add transportation vehicles under electrical devices, since there is a possibility that by the year 1990 we will have some electric-powered automobiles, but no one can rely on viable technology in 1990 at this stage of the game, in my opinion.

So the critical sector is liquid fuels, and where will we get that from? It's got to come from our traditional source, crude oil, and from coal liquefaction, which we are here to talk about the next couple of days, and then from our oil shale processes.

We will also see some coal gasification in 1990, but there appears to be enough natural gas; therefore, it appears there is a little less incentive for us to gasify our coal as opposed to liquefy our coal.

We have also noted on this particular flow sheet, to further confuse it a bit, where some of the major environmental problems reside in this relatively complex, although simplified energy flow diagram.

We see, for example, the traditional water and land problems associated with strip mining. We see the problems associated with oil shale extraction. Anybody who has been out there realizes the tremendous quantities of material that have to be handled in order to get a reasonable amount of shale oil.

And then, of course, we have the coal liquefaction, coal gasification, and oil shale retorting array of problems, which unfortunately are multimedia. These appear to be pretty substantial in the air with the gaseous, liquid, and solid waste areas.

What this flow sheet suggests is that our environment is threatened, at least potentially, and that what we are really doing is moving away from the cleaner crude oil and natural gas into, at least from an environmental point of view, potentially dirtier oil shale and coal in order to meet our growing energy requirements, particularly in the liquid fuel sector.

With that as background, let me now explain how EPA's research and regulatory programs fit in with the synthetic fuel program. Of course, the production of synthetic fuels is not new. When I grew up in New York City in the 1940s and 50s, it was our natural gas. In fact, one couldn't pick up a newspaper without reading about another suicide. It was easy in those days to do yourself in very efficiently with carbon monoxide.

As you probably know, coal gas was first used in the late 1800s in London to light street lamps. Of course, more recently coal gasification is being applied on a commercial scale in Europe and South Africa.

In the United States today there are several low-Btu gas fires currently in operation. Perhaps you read in newspapers just today that the Federal Energy Regulatory Commission has just reversed itself and given approval to the American Natural Resources request for a huge high-Btu synthetic natural gas facility in North Dakota. So the experience has been primarily gasification, although particularly in South Africa, there is some experience with indirect coal liquefaction.

The types and quantitities of synthetic fuel pollutants differ substantially from the kind of pollutants that we in EPA are used to regulating. With the exception of the auxiliary steam generating equipment, synthetic fuel processes do not have the equivalent of a coal combustion stack gas which is intentionally vented to the atmosphere. Instead, synthetic gases are produced, usually cleaned of sulfur and other major impurities, and then used to produce the ultimate fuel product. At least, that is certainly the case in indirect coal liquefaction processes.

This helps explain why these synfuel processes generally have relatively low but still significant emissions of the conventional air pollutants.

Whereas burning of the coal in boilers involves complete or close to complete oxidation of coal constituents, synthetic fuels are produced under reducing chemical conditions, which unfortunately from an environmental point of view, create a "Who's Who" in organic chemistry. There are high molecular organics, reduced sulfur compounds, and other contaminants that must be carefully handled to avoid serious air, water, and land problems.

So although in my opinion large-scale synfuel plants have a potential for monumental environmental damage, we in the Agency are convinced that the application of available controls can minimize the environmental problems associated with production and use. In some cases, this technology will have to be borrowed from oil refining, coke production, and other industries, but we believe that all current environmental regulations can be achieved by intelligently planned and sited commercial facilities.

Cost studies for coal gasification and oil shale processing by EPA and DOE have indicated that such a level of environmental control can be achieved with acceptable costs. These studies estimate costs in the range of 5 to 10 percent of the final fuel product. Other studies have indicated higher costs, but I believe these are the most credible.

I must emphasize, however, that just conforming with existing regulations doesn't necessarily guarantee that the environment is being protected. The Agency is still concerned about the many potential problems. We do not yet have adequate information in areas where new regulations may be needed.

The Agency has plans for developing important regulations in the area of hazardous wastes, toxic substances, hazardous air pollutants, and groundwater protection, all of which we feel are essential elements for adequate environmental protection.

Now admittedly, it may be premature on my part but I will say it anyway: Even with the uncertainty in these regulations, I still feel good about synthetic fuels being able to meet current and projected regulations without astronomical cost impact. That will have to be validated and certified by the work that we will be doing together in the synthetic fuel environmental area.

What about our regulatory strategy? What's the Agency got up its sleeve as far as regulations for this synthetic fuel industry and coal liquefaction in particular? We are right now in the process of developing a regulatory strategy. Although such a strategy is in the relatively early stages of development, its major goal will be to promote the incorporation of best available controls for all major synthetic fuel facilities.

Current thinking is that such an approach would involve near-term publication of what we call push control technology documents for the major synfuel processes. These are probably the most important near-term documents in the Agency's regulatory armament. Although not legally binding, they would document the controls the Agency believes represent state of the art and will be used by the EPA regions as an important source documenting the permitting process. It will be the focal point for discussions with the synfuel industry representatives and the public at large.

These documents would ultimately be superseded by the legally binding technology-based standards such as the New Source Performance Standards, the water effluent guidelines, and other control technology-based regulations when sufficient information is available for their promulgation. We are aiming in the Agency to publish these documents in 1981. There will probably be one on indirect coal liquefaction and one on direct coal liquefaction.

The time frame for the control technology-based regulations is less certain. Since it is not known when sufficient information will be available for these legally binding regulations, we will be hearing later on in our program about our Air, Water, and Solid Waste Offices' preliminary plans in this area; however, it is expected that the very earliest that such legally binding regulations could be promulgated is in the post-1982 time period.

We feel that the development of the guidance documents and ultimately the standards for synfuel industries presents a unique opportunity in the environmental game to establish controls at the same time that processes are being developed and commercialized. We hope that success in this endeavor will mean that industry can be spared costly retrofit. We hope that controls can be put in early, not after plans are complete.

I think this opportunity is generally recognized by the industry. We have been pleased so far with the cooperative spirit the industry has shown. This is particularly evident in the oil shale sector of our deliberations since we have done more with industry in the oil shale area than we have in the coal liquefaction area.

In the research side of the picture we have been involved in the synthetic fuels business since the early 1970s. The program was expanded substantially in Fiscal Year 1975, which was the first year of the EPA-managed interagency energy program.

The EPA Program can be divided into two complementary sub-programs: the environmental assessment/control technology effort, which evaluates the needs for and effectiveness of control technology; and the health and ecological sub-program, which defines the magnitude of synfuel health and ecological impacts.

Our funding in this area has been on the order of $12 to $15 million per year since Fiscal Year 1975 - a fairly modest funding level, I believe. The control technology part of the program is about $7 million.

Let me discuss some specific funding levels in 1979 and 1980 in that area. Our total Energy Control Program in 1979 was approximately $58 million. Our synthetic fuels work is included in the $12.6 million allocated for fuel processing, and it includes not only synthetic fuels but fluidized combustion, coal cleaning, and some of our liquid treatment work as well. The synthetic fuel component of that is about $7 million, roughly $5 million in coal-related synfuels, and the remaining $2 million in oil shale and alcohol-related work. But that puts our program in perspective. It's a relatively small program even compared to our total program, which is, by DOE standards, fairly modest.

I would like to briefly summarize some of the major findings of our research program to date. Bob Hangebrauck and Norb Jaworski of our RTP laboratory will focus in particular on the coal-related synfuel work.

But we have characterized emissions from several commercial coal gasification units via bioassay, biological tests, Ames tests, and other biological tests and chemical techniques. Quite frankly, we find the potential for a truly monumental problem. Some of the gas, for example, contains a wide array of potentially carcinogenic organic compounds; however, we remain optimistic that with careful housekeeping and controls we can minimize any potential environmental problems.

We have performed fairly detailed engineering studies on Lurgi coal gasification systems, which of course are the gasification end of that system before the methanation step. They bear a strong relationship to some of the indirect coal liquefaction processes. We have carefully defined the control technology needed to meet current and, to some extent, projected environmental regulations.

Again, as I indicated earlier, although some of the information on the technology for methanation is somewhat speculative since we are borrowing from related industries, we feel there is a high probability that such controls would be effective. These controls are projected to increase the capital cost of a Lurgi gasification plant by 5 percent and operating costs by about 10 percent.

These numbers encourage me to think that we can work very closely with the synthetic fuel industry. We will need more work to verify the accuracy of these numbers. But if in fact we are only talking about a 10 percent impact to meet all current projected regulations, I would hope that the industry would not be very negative toward our regulatory approach and that we could work together cooperatively toward an intelligent regulatory program.

We have also performed studies on disposal of spent shale, which I think are relevant to coal liquefaction. These studies indicate that careful reclamation practices can achieve successful revegetation. This is a particular problem in the West where rainfall is sparse; however, leachate studies have indicated that an impermeable layer may be needed to prevent leaching of hoods into groundwater since it looks like spent shale is fairly porous. This may also apply to some of the solid waste associated with coal synthetic fuel plants.

Both EPA and DOE have found that the toxicity and mutagenicity of synfuel products and byproducts is fairly active. Bacterial end studies indicate that biological activity, while varying over two orders of magnitude depending upon the synfuel process sampled and other variables, appears to be greater than for natural petroleum products. So I think the handling of the products is something we will also have to be careful with, in addition to the control of effluents and emissions from the plants themselves.

That describes the kind of things our research program has been doing in the past, but we are now talking about an accelerated program. We are talking about taking some of the monies from some areas outside of the synthetic fuel program, such as our conventional coal combustion program, and putting them into the synthetic fuel area with the aim of accelerating our efforts.

We are also requesting additional funds in Fiscal Years 1980 and 1981 through our zero-base budgeting process and through our normal budgetary process through the Office of Management and Budget. Time will tell whether we are successful in getting these extra funds but, in any event, the Agency will reprogram funds within its current funding obligation to accelerate this program.

We feel such an acceleration is needed since corporations know that environmental controls, in addition to protecting the environment, can also help speed the permit process and licensing time.

We think that if you can convince the environmentalists, if you can convince Indians who have land that might be impacted by the synthetic fuel process, that you have put in the best available controls, it's going to make the whole licensing/permit process a whole lot easier so there can be a synergistic relationship between the regulators and those being regulated.

So we in our research program will accelerate our efforts to evaluate control technology for major streams at first- and second-generation synfuel processes. We will focus on coal liquefaction, direct and indirect gasification, oil shale processes, and perhaps even some of the methanol biomass processes. Primary and secondary pollutants through these processes will continue to be identified in quantities estimated. Control methods will be identified and carefully evaluated. Air, water, and solid waste effluents will be considered in various synfuel sources including conversion steps, and we anticipate that our major near-term output, as I indicated, will be the previously described pollution control technology guidance documents. Concurrent and subsequent research will support the actual legally binding technology-based standards sometime, as I indicated, after 1982.

Our prospective health and ecological research sub-program, which we are not going to hear much more about today -- we are primarily engineers at this particular meeting -- will hinge on the development of a firm data base related to environmental effects of synfuel technologies. Major objectives will include identifying the magnitude of health problems, particularly occupational health problems, which may be the most severe potential problems.

Another major goal is establishing quantitative impacts of liquid and gaseous pollutants and solid wastes on natural and managed ecosystems. They will also in that part of the research program form an intra-agency synfuel environmental effects evaluation team, which is planned to support the permitting activities and provide necessary information relating to synfuels and other new technologies.

So this is the job before EPA. Much research, much in the way of regulatory activity is needed so that we can prepare guidance documents and standards. These air, water, and solid waste standards must be devised as the synthetic fuel industry commercializes. This puts pressure on our regulatory colleagues to generate standards with less than desirable amounts of information. This is obviously quite a challenge.

Despite all these problems, though, the Agency feels that a synfuels industry should be developed. We are approaching the synthetic fuel industry positively. I think I can speak for the Agency in saying that we are not out to torpedo such an industry. Our job is to not discourage commercialization of this critical industry but at the same time to protect the environment. This is quite a challenge.

In my opinion, coal liquefaction is the most important of all the synthetic fuel technologies because it produces liquid, which is our primary energy problem, from coal, our most abundant domestic resource. This particular meeting, which is emphasizing coal liquefaction, can be instrumental in helping the Agency achieve its goals. We hope it will begin the process of forging the communication links necessary for industry and the Agency to work cooperatively toward realistic control technology standards.

Sid Thomson, Fluor Corporation: What was the basis for the 5 percent figure you quoted?

Mr. Princiotta: That number comes from a report produced for us by TRW on synthetic natural gas. It's one of our environmental assessment series and I believe it's the most comprehensive report of its kind, looking into the various air, water, and solid waste controls. The numbers add up to 5 percent of the total cost of the gasification plant, which, of course, is not inconsiderable. We are talking about a plant costing more than $2 billion.

Mr. Thomson: How many plants has TRW built? How many Lurgi gasifier plants has anybody built in this country?

Mr. Princiotta: I don't believe any gasification plants have been built in this country.

Mr. Thomson: Not in this country.

Mr. Princiotta: Do you feel that the numbers are unreasonably low?

Mr. Thomson: I believe they are unreasonably low.

Mr. Princiotta: What do you think a better number might be?

Mr. Thomson: Ten to fifteen percent of capital costs.

Mr. Princiotta: I appreciate that input and we would like to chat a little further on that. That's what we are here for, quite frankly. We don't want to get inbreeding.

We do have our own array of contractors but many of them, as you point out, don't have a lot of synthetic fuel commercial experience. Not many contractors in this country do. I think Fluor and several other firms represented here are unique and we would like to pick your brains.

Mr. Thomson: I believe the most important consideration is the method of estimate preparation. Until a commercial-size plant is constructed and total costs tabulated, a firm base for estimating cannot be established.

Mr. Princiotta: I am sure you are right.

Mr. Thomson: And paper studies are just that. They are paper studies.

Mr. Princiotta: A good point.

Bill Rhodes, EPA: Some of the problems we have when we go through the estimating process, of course, are deciding what really is control technology and what is process technology. In many cases we found out that major differences are caused by what you put into which category. We certainly would like to pursue this with Fluor or anyone else.

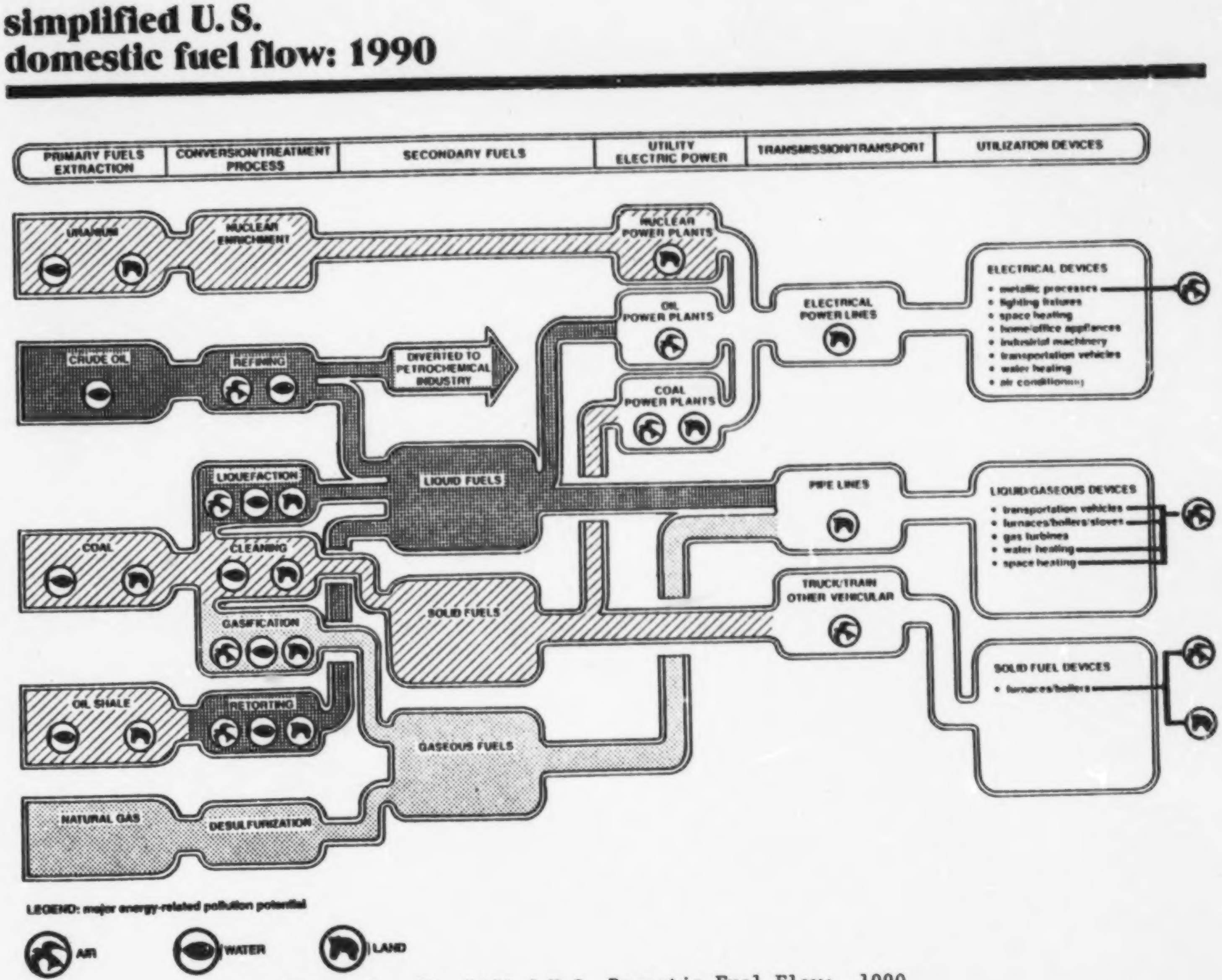
simplified U.S. domestic fuel flow: 1990
PRIMARY FUELS EXTRACTION
CONVERSION/TREATMENT PROCESS
SECONDARY FUELS
UTILITY ELECTRIC POWER
TRANSMISSION/TRANSPORT
UTILIZATION DEVICES
URANIUM
NUCLEAR ENRICHMENT
NUCLEAR POWER PLANTS
OIL POWER PLANTS
COAL POWER PLANTS
ELECTRICAL POWER LINES
ELECTRICAL DEVICES
• metallic processes
• lighting fixtures
• space heating
• home/office appliances
• industrial machinery
• transportation vehicles
• water heating
• air conditioning
CRUDE OIL
REFINING
DIVERTED TO PETROCHEMICAL INDUSTRY
LIQUEFACTION
LIQUID FUELS
PIPE LINES
LIQUID/GASEOUS DEVICES
• transportation vehicles
• furnaces/boilers/stoves
• gas turbines
• water heating
• space heating
COAL
CLEANING
SOLID FUELS
TRUCK/TRAIN OTHER VEHICULAR
GASIFICATION
SOLID FUEL DEVICES
• furnaces/boilers
OIL SHALE
RETORTING
GASEOUS FUELS
NATURAL GAS
DESULFURIZATION
LEGEND: major energy-related pollution potential
AIR
WATER
LAND

Figure 1. Simplified U.S. Domestic Fuel Flow: 1990

Mr. Princiotta: As I recall, for example, much of the gas purification system, particularly the methanol sulfur clean-up equipment, would not be considered control since that would be needed anyway in a gasification process. That was a pretty expensive item, as I recall. So that is one of our main problems, coming up with intelligent costs.

Bruno Loran, Ralph M. Parsons Company: I'm wondering how you arrived at the assumption that indirect liquefaction is about three times more important than direct liquefaction.

Mr. Princiotta: It looks like indirect liquefaction may have advantages but direct liquefaction is a much simpler technology and requires less equipment.

I would defer on that to my Department of Energy colleagues. What I have essentially done is rely on their staff work. They seem to think that in any crunch program toward early commercialization the indirect processes are going to make the impact.

We'd like to hear more from each of you on that, but my understanding is that the SASOL kind of technology is commercial, whereas I am not aware of any direct liquefaction technology that is even close to commercialization. I think we are ready for a demonstration plant at best.

We may have some preconceived opinions but no irreversible preconceived opinions. You might want to discuss some of the things EPA is after at a meeting like this. One of the major things we are after are commercialization plans. What do you experts see as the kind of liquefaction technologies that are going to be coming on board, in what time frame? Are these indirect liquefaction processes a mirage? Are they not going to come in these plans? Are they too expensive or are there too many other related problems?

These kinds of questions are critical for our program. We have limited resources and we want to put our resources where the action is projected to be. Who knows where it actually will be better than the industry itself?

John Accardi, EPA: Does ORD have any plans or have they done any studies on the water requirements of this process and its effect on the Western states?

Mr. Princiotta: We sponsored a study through the University of Oklahoma and the Radian Corporation. They studied that issue fairly completely.

The State of Colorado and the Department of Energy have performed studies as well, and quite frankly, the bottom line of all the studies in this area seems to suggest -- and again we'd like input from the experts -- that the water is there in the kind of quantities needed for a massive synthetic fuel program even in the West.

In fact, some of the oil shale companies suggest that in oil shale country -- by definition that is in the arid basin area in Colorado -- they have already acquired water rights somewhere in the range of one to two million barrels a day production capacity.

All the studies I have seen - EPA, DOE, and state studies - seem to suggest the water is there. But there are a lot of politics involved in getting rights to this water and I think it's complicated and not amenable to a simple paper study. I think that there is going to be a case-by-case determination but I do know that the oil shale companies have stated publicly that they already have enough water for shale oil production in excess of one million barrels a day.

Let me just spend a minute or two discussing the agenda. We will hear directly from the regulatory people in the Agency about some of the procedures, activities, and plans in the air regulatory area, particularly the New Source Performance Standard activity. Jack Farmer will be discussing this.

We will be hearing from our Solid Waste Office on their standard-setting procedures and activities relating to solid waste regulations, particularly the RCRA. The so-called hazardous waste regulations will be discussed. We will also discuss in more detail EPA's research program activities, particularly the control technology portion of the research program. Norb Jaworski, Assistant Deputy Director of our research laboratory in North Carolina, and Bob Hangebrauck will discuss that. Tomorrow, Bill Telliard will discuss water-related standard activities and Terry Thoem from Region VIII will talk about some of the permitting procedures as they relate to synthetic fuel processes, particularly coal liquefaction.

And then, of course, tomorrow we will also hear about plans by the industries themselves. We are very anxious to receive any data you may have in the environmental area, for example, control technology cost data.

Mr. Princiotta then introduced Jack Farmer of EPA's Emission Standards and Engineering Division.

Standard Setting Procedures, Activities, and Plans Relating to Air Emissions from Coal Liquefaction: Jack Farmer, Emission Standards and Engineering Division, EPA.

I appreciate this opportunity to be with you this afternoon and talk about our standard setting procedures and activities.

The Emissions Standards and Engineering Division has the function of developing New Source Performance Standards and also standards for hazardous air pollutants. Both of these standards are authorized under the Clean Air Act. Section 111 of the Act covers the New Source Performance Standards and Section 112 covers the standards for hazardous air pollutants.

A New Source Performance Standard applies to affected facilities that commence construction after a standard is proposed in the Federal Register. Existing sources are not subject to New Source Performance Standards unless these sources are modified to increase their emission or unless they are reconstructed. A New Source Performance Standard is defined to require the application of the best system of emission reductions, taking into account the cost and any non-air quality health and environmental impact, and energy requirements.

To date we have published New Source Performance Standards for 27 source categories and we have proposed New Source Performance Standards for four additional categories. During the coming year we plan to propose standards for an additional 15 source categories and to issue final standards for six categories.

On August 21, 1979, we issued a priority list of source categories for which we will be developing standards over the next few years. In 1977, Congress amended the Clean Air Act. One of the amendments to Section 111 directed the Administrator to develop a list of stationary sources for which we had not developed New Source Performance Standards. Congress further directed us to issue standards for the source categories on that list by August 1982.

As I said, in August 1979, the priority list was published and on that list there were 59 source categories in addition to the 27 categories already regulated. You can see that we have quite a few source categories that we are going to be working on in the next few years.

Hazardous air pollutant standards will apply not only to existing but also to new sources. We consider a hazardous pollutant one that may cause or contribute to an increase in mortality or an increase in serious irreversible or incapacitating reversible illness. So far we have standards for four hazardous pollutants: asbestos, beryllium, mercury, and vinyl chloride. We have also listed benzene as a hazardous air pollutant and are in the process of developing regulations. We will in the next year publish proposed regulations on four benzene emission source categories.

On October 10, 1979, we published some proposed procedures and policies on dealing with carcinogens under Section 112 of the Clean Air Act. It is called Policy and Procedures for Identifying, Assessing, and Regulating Airborne Substances Posing a Risk of Cancer. The Policy is out for comment now. We will be holding public hearings later on. After considering all the comments, we will issue the final procedures and policies later on next year.

Our New Source Performance Standards Program has grown significantly since 1977, primarily because the Clean Air Act directs us to develop standards for all source categories for which standards have not been developed.

Some figures may give you a feeling for the size and magnitude of our program increase. Our program funding in Fiscal Year 1978 was $8.5 million. In Fiscal Year 1979 it went to $16.2 million and in Fiscal Year 1980 we expect a budget in the neighborhood of $29 million, so it's roughly doubled each year since 1977.

Even though our budget has undergone a significant increase, the staff has not increased at all. We have been required to turn to contractors for support in our standards development efforts. We have eight prime contractors who are working with us in the standards development area. In addition to these eight contractors, we have support from other contractors in the areas of emission measurement and economic analysis.

I would like to discuss very briefly our procedures in standards development. Before we got into the contract business we did not have a detailed blueprint or a procedures manual for setting New Source Performance Standards or hazardous pollutant standards. We all did our work in-house and it wasn't necessary to sit down and develop a cookbook.

However, since we now have eight contractors working on standards development, we decided that one of the first things we had to do was to come up with a road map for them, so we set about developing a very detailed procedures manual. It turned out to be a very good thing because it's helped the contractors and us immensely in getting the projects going.

I think of the development of a standard much in the same way as I think of the construction of a building or a chemical plant. If someone builds a plant or a building, they start by developing a set of blueprints, which is like our contract manual, and they put together a lot of construction materials and wind up with a structure that has a specific purpose in mind.

When we develop a standard we do much the same thing. We start by gathering a lot of information and end with a stack of paper that has a lot of words on it and each of the words means something and the regulation has a specific purpose.

It takes us about two years from the time we start a project until we actually get a proposed standard published in the Federal Register. After we publish a proposed standard, an additional year is required to hold public hearings, receive comments on the proposed standard, evaluate all those comments, make changes to the proposed standard, and then issue the final standard in the Federal Register.

The standards development process has three basic phases. The first phase is a very short-term intensive study which lasts about 12 weeks. The purpose of this phase is to characterize the particular source category that we are studying and determine whether a standard is appropriate for that category. Believe it or not, in some cases we evaluate industries and conclude that a standard is not appropriate, and discontinue the project. This evaluation process allows us to avoid unnecessary regulations. If we do conclude that a standard is appropriate, we then decide what pollutants and facilities should be regulated.

The second phase is the data-gathering phase. We search the literature, talk to trade associations, visit plants that are involved and any other thing we can do to gather information. We usually select at least a couple of plants that have very good control systems and then conduct a detailed emission measurement program around those particular plants.

Once we have acquired sufficient data to develop a standard, we move into the third phase, which is the analysis and evaluation phase. We do all the analysis and evaluation we need to do, and then develop recommended standards. These recommended standards undergo extensive review before they are proposed in the Federal Register. This review is done both within and outside of EPA.

As far as an outside review is concerned, we have an advisory committee, which is called the National Air Pollution Control Techniques Advisory Committee. We meet with this committee several times a year. Three to four weeks before we are scheduled to meet with them we send the committee the recommended standard that we are going to discuss with them. At the same time we send copies to the affected industry and to environmental and public interest groups. The meetings are in the form of a public hearing. We present our recommendations at the meeting, and then the industry and environmental and public interest groups present their comments. The committee members evaluate our recommendations in light of what the industry representatives and others say and then tell us how they feel about the recommended standard and the issues raised about them.

The review within EPA is done both at a working level and a policy level. The purpose of these reviews is to ensure that recommended standards are reasonable and consistent with overall Agency policy.

Again after we propose a standard, we go through a public hearing and comment period which lasts about 60 days. About a year after the proposal we are able to publish a final standard.

Once a final standard is published, the Clean Air Act provides for a 60-day period during which anyone may petition a review of the standard. If someone does file a petition, we move into the litigation phase.

Now I would like to briefly cover our standards development program in the synthetic fuels area. This program is in the very early planning stages, and I am not really able to provide you with much more information than Frank gave you this morning. At this time, we have not initiated any standards development project for a synthetic fuel process; however, we are seriously considering starting a project on low-Btu gasification. If we start the project by the end of 1979, we will be ready to propose regulations in about two years.

A few years ago we did have some projects going on in the synthetic fuels area. We were working on standards for the Lurgi coal gasification process for making synthetic natural gas and we also had a project on low-Btu gasification. In 1977 both of these projects were dropped because we had very limited resources and neither of these projects had a high priority. We did publish a guideline document on the Lurgi coal gasification process; it is merely a compilation of all the information that we had gathered during our standard development activities for Lurgi coal gasification.

That's the extent of our program and activities in the synthetic fuels program at this time.

Mr. Princiotta then introduced Yvonne Garbe of EPA's Hazardous Waste Management Division.

Standard Setting Procedures, Activities, and Plans Relating to Solid Wastes from Coal Liquefaction: Yvonne Garbe, Hazardous Waste Management Division, EPA.

When Frank asked me to speak today for about 30 minutes on our standards setting procedures and activities for hazardous wastes, I wondered at first how I was going to be able to set it out in a half-hour. After consulting our legal counsel regarding what I could and, more specifically, what I could not say, I find myself faced with the dilemma of what I am going to do with the 25 minutes of my allotted time.

We are in a phase of our regulatory rule making that does not allow me to say anything specific. As you know, EPA was charged by Congress in 1976 with establishing a regulatory program to control hazardous waste. In December 1978, we published a list of proposed regulations on which we have since received over 1,200 sets of comments. When you place all these comments side-by-side or on top of each other, they reach over seven feet high.

Our comment period was closed in March, and under the laws governing rulemaking, EPA is required to read, digest, analyze, and respond to every major point made by every commenter. At this time our entire office is measurably consumed in this effort, along with making revisions and modifications to the regulations to reflect these comments.

We were originally scheduled to publish final regulations by December of 1979; however, on October 13, 1979, the court granted EPA a time extension. It now looks as if we will be coming out with something more specific in April 1980.

Again, under the circumstances I can't be too specific about any of our changes or internal decision making, and I also can't receive any comments at this time, but I can explain a little bit about the structure of our hazardous waste program and perhaps give you a very general idea of the kinds of regulations you might be facing.

Subtitle C of RCRA provides for a cradle-to-grave management system for hazardous waste. The system is delineated under Sections 3001 to 3006 and 3010 on all proposed hazardous waste regulations.

All non-hazardous wastes are addressed in Subtitle D standards. Under 3001 we began with the identification of the hazardous waste. Generally, anyone who generates or receives waste is bound to subject that waste to a series of tests to identify whether it is hazardous or non-hazardous.

Basically, there are two methods for determining whether you have a hazardous waste. It is hazardous if it's on the list published by EPA. Of course, EPA can delete or add to this list as long as this program is in existence. According to the other method, if your waste has one of four characteristics: ignitability, corrosivity, reactivity, or toxicity, then you have a hazardous waste on your hands. All of the wastes that are identified as hazardous are subject to the standard established under Subtitle C.

When we talked about proposing the Subtitle C regulations, which deal primarily with the handling, transport, treatment, and storage of these wastes, it soon became very obvious that there were some types of waste to which these standards would not be directly applicable. Therefore, EPA established a special waste category.

In general, EPA describes these wastes as being high-volume wastes, those wastes whose composition, characteristics, and degree of hazard are not readily known but which are believed to have a low risk of hazard. There is very little information available as to how to treat, store, handle, or in general manage this type of waste, and it just did not seem fair to the industry to say if you have this type of hazardous waste, you should have to subject it to the Subtitle C specification or regulations, which are very, very stringent.

Some examples of the types of waste in this category were identified in our proposed rulemaking. They are metal mining wastes, phosphate mining and processing waste, uranium mining waste, gas and oil drilling muds and oil production brines, cement kiln dust, and utility waste.

Now, because we don't know very much about them and how to manage them, we are putting these on a kind of reserve. We are initiating studies that will specifically pull out the kind of detail and data that are necessary for us to promulgate regulations tailored for these industries.

During our open-comment period we received several suggestions that coal liquefaction waste, that is, slag, char ash, and sludge be included under the special waste category. All I can say at this point is that we are seriously considering the suggestion. At this time, however, we do not know specifically what volumes of solid waste might be generated from the industry. We don't know very much about the composition, the degree of hazard, if any, or the technologies that are available and needed to control these wastes.

Even so, we do have a limited amount of information and it indicates that we should be concerned with a great majority of these wastes. Examples are ash and slag consisting of metallic oxides and trace element compounds, coal and char particles containing organic and mineral materials, wastewater treatment sludges, and mixtures of coal tar residuals and coal fines. These may also contain untreated organic and toxic materials. Some other solid effluents that we're considering or concerned about are spent catalysts, spent sulfur guard reactor absorbents, fugitive dust from coal and limestone piles, and ash from utility boilers.

The Office of Solid Waste will be working very closely with our Office of Research and Development to study these wastes and to provide some guidance that the industry is anticipating in the forthcoming pollution control guidance document. Once this document is developed it will help the industry interpret and implement regulations that will be promulgated next April, that is, the applicable portions of Subtitle C regulations, as well as provide some indications of the nature of the regulations that will be written in the future.

Once again, I apologize that I cannot be too specific.

Sid Thomson, Fluor Corporation: Is testing of the ash from existing coal-fired boilers going to take a high priority in your investigations into solid waste?

Ms. Garbe: Well, everything is relative. I am not sure what you mean by a high priority.

Mr. Thomson: It seems to me as that you have a large existing source of material that could be tested without delay. In this manner, ash disposal problems could be solved or at least defined before the synfuels program gains momentum.

Ms. Garbe: Well, as I indicated, we have already identified utility waste under a proposed regulation. There is a study that is about to be awarded, if not just recently awarded, that will include that.

This was one of the comments we received: Is coal liquefaction waste going to be included under this broader title of utility waste? That has not been decided yet, and if it is, it may be included in the study that has already been awarded. If not, it may be that we might go on for an independent study.

Because the proposed criteria require that the waste be large-volume, low-hazard, and generally disposed of close by in a mono-filled landfill, we don't know if waste from coal liquefaction would qualify for that. That has to be decided.

There may be smaller wastes such as spent catalysts that would not qualify, and therefore would be subject to the Subtitle C regulations for hazardous wastes.

Terry Surles, Argonne National Laboratory: Would there be any reclassification of these fly ash or bottom ash wastes somewhere down the road for, say, industrial coal users? Has any thought been given to that or has any timetable been developed for either simply calling them solid wastes or reclassifying them as hazardous?

Ms. Garbe: Is your question, could they be reclassified from hazardous to non-hazardous or vice versa?

Mr. Surles: Or are they just going to leave them as special? Is there any additional work being done?

Ms. Garbe: Oh, yes, very definitely. I think I am warming up to your question right now. That is the intent of the study. At the end of the study we will be better able to determine which fractions of those wastes are hazardous. Some may very well be dumped into the category of just routine hazardous waste and then be subject to the full set of Subtitle C regulations.

On the other hand, we may identify wastes that we consider do not have to comply and we may tailor more specific regulations for them, depending on the nature, the content, the characteristics, and a few other things.

So to answer your question, yes, they will be reclassified and it depends primarily on the results of the study.

Mr. Surles: Who is your contractor on that?

Ms. Garbe: Because I don't know if it was awarded or not, I don't know if I should say.

Dick Crosthwait, Mobil Corporation: This is a question directed to both you and Jack. In view of the volume of comments that you got from the RCRA regulations that are being questioned and the court's extending time, my opinion is that we don't have enough industry input into the regulations early in the game. There is a lot of industry expertise that comes in after the fact because they haven't had the opportunity to share their experience with similar processes and situations. Jack implied that there is early industry input in the New Source Performance Standards. The CTGs, however, are part of the State Implementation Plans and become law without going through any process of comment and public input and without using the expertise of the industry. Is there any effort to try and improve that aspect?

Mr. Farmer: You get more involved whenever the state goes through their rulemaking procedures to adopt it as a regulation. I wasn't involved in the CTG program directly but I know there was some industry input. It wasn't as intensive as the industry input is for standards.

Mr. Crosthwait: Agreed.

Mr. Farmer: At least it didn't have as much time on the CTG as we do on the standards development projects.

Mr. Crosthwait: Even there I think that by the time it's first published it may be too late to really get the useful industry input, so you are wasting time in replying to the volume of comments.

Is there any thought on trying to encourage a reversal of the Muskie syndrome that sees government and industry as antagonists?

Mr. Farmer: We don't have any active program going to develop the CTG on any industry at this time. I'm not going to say that we won't eventually develop some CTGs but the CTG program is currently in a holding pattern.

If we decide to develop CTGs, an effort will be made to get industry input no matter what industry is doing.

Mr. Crosthwait: I think I heard that we were trying to develop some CTGs with the Central Industry.

Mr. Princiotta: We are going to clarify that a little bit. Before we do that, Jack, why don't you explain industry's opportunities for input in the normal standard process?

Mr. Farmer: Whenever we start a standards development process, we put out thick documents containing data to support all of our standards. There are about three chapters in the core of these documents that discuss the industry, the characteristics, and the control technology applicable to the industry. All of this is put together early on in copies that are distributed to all the industries. That is the factual part of the document, so to speak, that doesn't have any decisions in it but outlines the facts as we see them.

Industry has an opportunity at that point to get back to us and give us comments on whether we have misinterpreted the facts, or don't have all the facts, or have them incorrectly.

Now, the first time you get a chance to really see our thinking in terms of a standard is when we go to the National Air Pollution Control Techniques Advisory Committee. That's about a year before proposal, so we still have a long interval between the time we go to the advisory committee and the time the regulation is actually put in the Federal Register. We actively solicit input all the way through and the advisory committee draft has all the comments. We need a follow-up to do that.

So we make a great effort to get input not only from industry but from any environmental or public interest group, because sometimes they will get very active on some of these hazardous pollutant standards and we have to meet with them just as much as with the industry.

Yvonne was saying that once you get the regulation proposed in the Federal Register you can't have any ex parte communication. That's why she is limited in what she can say. Once we get the regulation proposed everything has to be official and aboveboard. We have to have written documents and we can't sit down and meet with you as freely as we can before a proposal. That's why we make a great effort to try to get all your input before it's actually proposed.

Mr. Crosthwait: I agree. I'm saying how can we accelerate that because seven feet of comments were received on the RCRAs, seven feet of comments that could maybe have been handled beforehand.

Mr. Farmer: I don't know about theirs but I know about ours. We had similar experience in which we had very close communication with the industry and still you end up with whole drawers full of comments. It's a matter of disagreements. Just because we sit down and meet with you doesn't necessarily mean we are going to agree with everything you are saying, so when we disagree you are still going to come back with seven feet of comments and we still have to deal with them.

Ms. Garbe: I think that ours is even more difficult because we are coming out with a hazardous waste regulatory program that, instead of being industry-specific, will cover just about every industry across the nation. We only have 28 people back at headquarters right now who are involved in this program. It would be very difficult to meet with each of the industries.

I think that particularly in the special waste category, and that's where I am working closely right now, we are making an effort to meet with the industry from the onset. I will give you a good example. I am in charge of a project to study the mining industry. In an effort to meet with the industry and get their inputs right at the very beginning, we have a Mine Solid Waste Coordinating Committee which meets to talk about the industries, the mine sites we are going to, the way we are going to sample their waste streams, and the types of data we are going to collect. They have input right at the beginning. I must say that at first there wasn't a great meeting of the minds, but after two or three meetings, I think we are establishing a better rapport. It is to their benefit as well as to ours to do it this way and I hope that we are setting a precedent for all of the special waste studies in this area.

I can only address that particular category in that kind of approach. Naturally, we are not going to be launching a set of studies for each of the industries across the board for all of the hazardous waste categories, but that's one effort.

Barnet Groten, Texas Eastern Corporation: Is there any uniformity in classifying waste, for instance hydrocarbon waste, coming from a hydrocarbon refinery as opposed to a similar or an identical waste coming from a coal liquefaction plant? How is that discriminated? Is it by content of the waste or industry source or what?

Ms. Garbe: I'm sorry. I am not going to be able to answer that. Anything I would say would probably be incorrect. All I know is that they do have specific compounds that are on the list. Now, whether they are on the list in conjunction with other chemicals that makes them more hazardous or non-hazardous, I really don't know.

I suggest perhaps after the meeting I give you a number you can call and ask them more specifically.

Mr. Princiotta: I think I might be able to shuffle a little bit of what Yvonne mentioned. In the utility ash and sludge study we recently selected Arthur D. Little, Inc., to look only at utility bottom ash, fly ash, and flue gas desulfurization sludges, just so we get that straight now.

Mr. Princiotta then introduced Norbert Jaworski of EPA's Industrial Environmental Research Laboratory.

Overview and Objectives of R&D Activities in Coal Liquefaction: Norbert Jaworski, Industrial Environmental Research Laboratory (RTP), EPA.

I am Deputy Director of the Industrial Environmental Research Laboratory at Research Triangle Park, North Carolina. Today, I will focus my remarks on an overview and objectives of the Laboratory's coal liquefaction program.

A simplified version of the organizational structure of EPA, depicting the ORD groups involved with direct liquefaction, is given in Figure 2. The Office of Research and Development is headed by Steve Gage. Including all EPA research activities, it is divided into 5 basic programs and 17 laboratories across the country. Our Laboratory reports to Dr. Reznek of the Office of Environmental Engineering and Technology.

Under the OEET, we have a sister laboratory (IERL/Cinn) in Cincinnati that addresses different technologies. IERL/Cinn has responsibility for oil shale, in situ coal gasification, and extraction (mining, etc.) in the energy area; while IERL/RTP deals with coal gasification/liquefaction, combustion processes, and flue gas cleaning, as well as other areas such as coal cleaning and certain industrial processes.

Our Laboratory's activities related to energy fall into two major categories: first, environmental assessment, which is determining the environmental insults resulting from various technologies and the effectiveness and efficiencies of control techniques; and second, control technology development, a parallel activity. Our major emphasis in the energy program and the environmental assessment program really came out in 1975 with the interagency energy program.

At RTP, one of the major technologies we cover includes, of course, synfuels from coal. We also have a significant program in coal cleaning, both chemical and physical, with emphasis on physical coal cleaning.

Another program area at RTP has been conventional combustion; residual oil processing has also been part of our program.

In flue gas desulfurization, both regenerable and nonregenerable systems, we have made significant strides; for example, in limestone forced oxidation and use of adipic acid. Additionally, we have a large program in particulate control, both baghouses and electrostatic precipitators.

Another part of our conventional combustion program is NO_x control; that is, NO_x combustion modification. Although our SO_x, NO_x, and particulate program has focused primarily on the utility industry, in the last couple of years we have worked very closely with Air Programs on their industrial boiler program.

The last item is our fluidized bed combustion program. We had supported a miniplant at Exxon and are now working closely with DOE on its Georgetown and Rivesville facilities, emphasizing the environmental assessment of control technologies in the entire process system.

This basically is the R&D program in the energy area at RTP. We also have complementary work in industrial programs; for example, iron and steel, petrochemicals, and petrorefining.

I would now like to discuss the philosophy of our energy program. The formation of EPA resulted in the addressing of all media and environmental concerns by a single agency. Thus, an integrated, multimedia evaluation of an industry could be performed.

The emergence of the accelerated energy

program requiring an evaluation of problems parallel to the development of the technologies identified the need to develop a consistent, comprehensive evaluation system that would permit comparison between technologies.

Thus initially a great deal of effort was placed on developing procedures and protocols. For example, we developed a phased chemical analysis approach taking apart a complex chemical mixture. It's helped us in our analysis program, giving us the capability to compare technology against technology, effluent against effluent.

We also developed protocols for analysis of complex mixtures by biological testing. What we tried to do in our program is take those techniques that were fairly standardized for single compounds and then apply them to complex mixtures. We are also working significantly on cost consistency. For example, for the utility industry we have simple uniform cost relationships that our contractors can use.

Additionally, we consistently evaluate the commercial potential of the emerging technology in order to emphasize processes with the highest commercial potential. Two or three years ago, fluidized-bed combustion seemed to be the technology of the future and synfuels was farther down the line; however, in recent months we have been refocusing some of our fluidized-bed combustion and coal cleaning work and emphasizing direct and indirect liquefaction.

Of course, the purpose of our R&D effort is to support the Agency's regulatory program. We also feel our goal is to identify problems and solutions to the industry. Our Director has two signs: One says, "I am from the government. I am here to help you." The other says, "I am from industry. I am glad to have your help." We feel that we can support our Agency, and if we do our job right and work together, we can support industry at the same time.

In terms of our program office and regional office support, IERL/RTP's role is in problem definition: How do we really know what the potential harmful impact could be from a synfuels program? This translates into some of our environmental assessment reports. For example, if Jack Farmer of OAQPS says that 2 or 3 years down the line he wants to develop the research data base to be in a better position to develop a New Source Performance Standard, we are in a very positive mode here to define what data are really needed and required.

Also our synfuels program is helping ORD to guide our R&D in related areas. A good example is in the health effects area. In some of our initial screening programs we have come up with compounds that appear to be mutagenic. Thus, to the health effects groups, we can say, "This problem appears to be consistent across two or three technologies. You'd better take a look at this one because it's prevalent, and give us some better data in this area."

The synfuels effort also has applicability to New Source Performance Standards for industrial boilers.

Our two major areas of concentration are, again, indirect and direct liquefaction, SNG, and low- and medium-Btu gasification. Our early efforts focused on defining problems via our EA methodology system. We feel we have come quite a way with that. Our focus is now primarily dictated by the pollution control guidance documents. These documents require a sharper focus on environmental engineering aspects. What are our process modification capabilities? We have some bench-type units, one at RTP and one pilot facility at North Carolina State, where we can start modifying the process to see the impacts on various identified pollutants at different temperatures and pressures.

Of course, add-on treatment has been our classical way of handling some of our air pollutant and water pollutant programs. We are very concerned about design parameters. The bottom line, of course, and what we are working on now, is environmental control costs. So we are right now heavily into the engineering aspects of the environmental control systems. This will be one of the focuses of the guidance document.

Figure 3 will give you an idea why you might have a problem looking at EPA. Within ORD we also have to respond to the needs of the regulatory part of the Agency.

The three major Program Offices are the Office of Water and Waste Management; Office of Air, Noise, and Radiation; and Office of Toxic Substances. Each one of these Offices has been subdivided. For instance, the Office of Water and Waste Management includes the Office of Water Program Operations, Office of Water Planning and Standards, Office of Drinking Water, and Office of Solid Waste. Inside of this spoked wheel are various research committees that help interface with the Program Offices. So, for example, in the synthetic fuels area we interface with all three major Program Offices. They are all fed from the materials that have come out of ORD via controls research committees.

In summary, we have a very effective means of getting our research efforts funneled to our regulatory counterparts within EPA.

Mr. Princiotta then introduced Robert Hangebrauck of EPA/IERL-RTP's Energy Assessment

ENVIRONMENTAL PROTECTION AGENCY
(DOUG COSTLE)

OFFICE OF RESEARCH AND DEVELOPMENT
(STEVE GAGE)

OFFICE OF ENVIRONMENTAL ENGINEERING AND TECHNOLOGY
(STEVE REZNEK)

INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
RESEARCH TRIANGLE PARK
(JOHN BURCHARD)

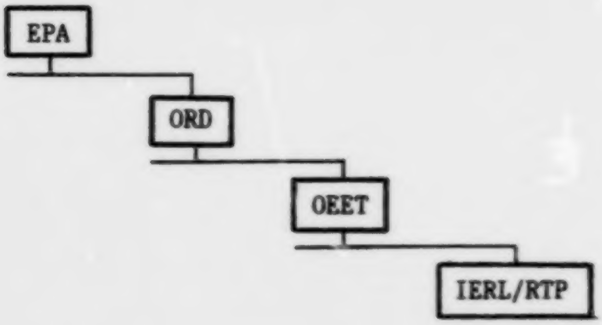

Figure 2. EPA Organizational Structure

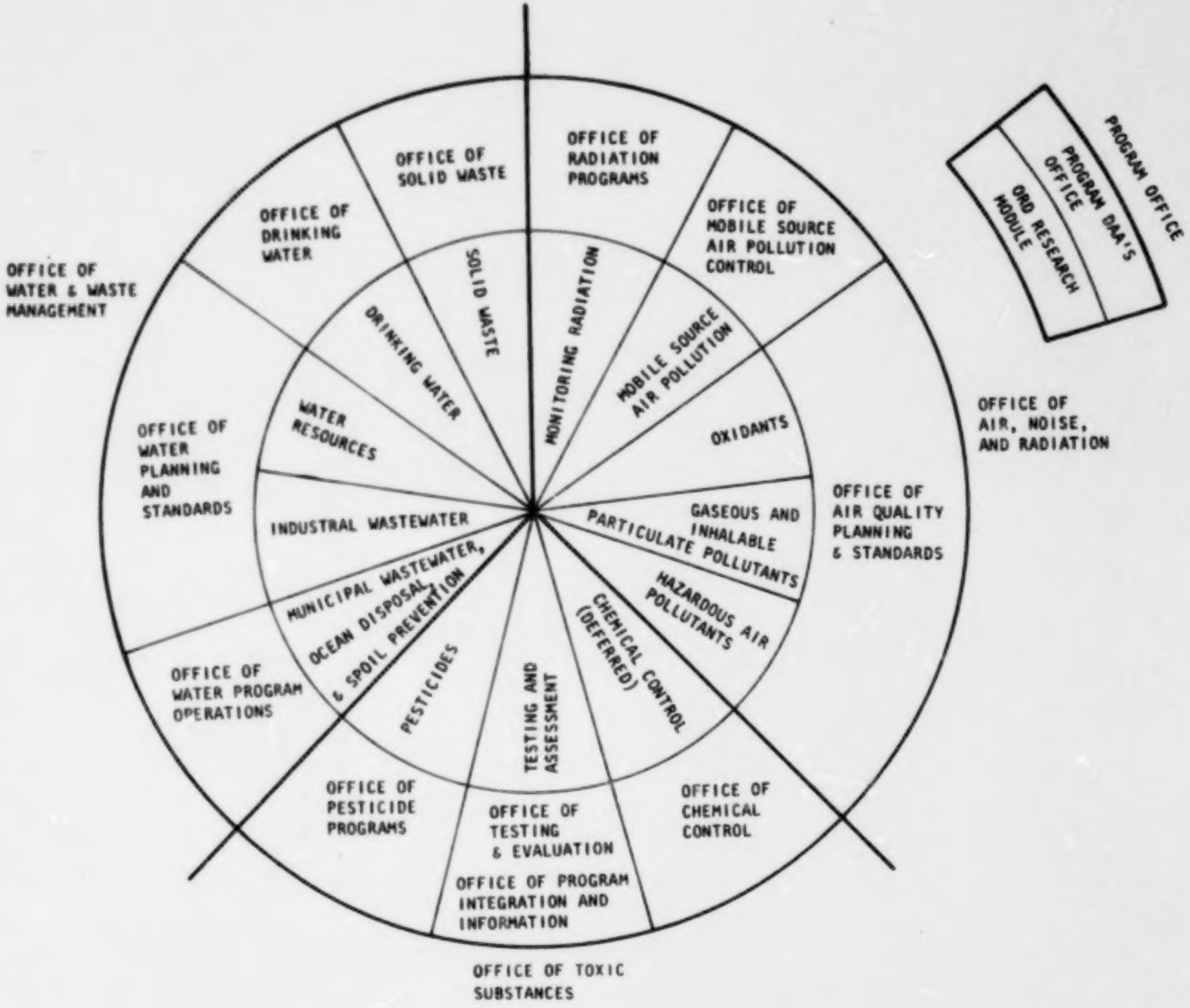
PROGRAM OFFICE
PROGRAM DAA'S OFFICE
ORD RESEARCH MODULE
OFFICE OF WATER & WASTE MANAGEMENT
OFFICE OF AIR, NOISE, AND RADIATION
OFFICE OF TOXIC SUBSTANCES
OFFICE OF SOLID WASTE
OFFICE OF RADIATION PROGRAMS
OFFICE OF MOBILE SOURCE AIR POLLUTION CONTROL
OFFICE OF AIR QUALITY PLANNING & STANDARDS
OFFICE OF CHEMICAL CONTROL
OFFICE OF TESTING & EVALUATION
OFFICE OF PROGRAM INTEGRATION AND INFORMATION
OFFICE OF PESTICIDE PROGRAMS
OFFICE OF WATER PROGRAM OPERATIONS
OFFICE OF WATER PLANNING AND STANDARDS
OFFICE OF DRINKING WATER
SOLID WASTE
MONITORING RADIATION
MOBILE SOURCE AIR POLLUTION
OXIDANTS
GASEOUS AND INHALABLE PARTICULATE POLLUTANTS
HAZARDOUS AIR POLLUTANTS
CHEMICAL CONTROL (DEFERRED)
TESTING AND ASSESSMENT
PESTICIDES
MUNICIPAL WASTEWATER, OCEAN DISPOSAL & SPOIL PREVENTION
INDUSTRAL WASTEWATER
WATER RESOURCES
DRINKING WATER

Figure 3. ORD Regulatory Office Coordination

and Control Division.

EPA R&D Environmental Assessment and Control Technology Plans in Coal Liquefaction: Robert Hangebrauck, Energy Assessment and Control Division, EPA/IERL-RTP.

I appreciate the opportunity to talk with you about our environmental program on coal liquefaction.

Table 1 lists the technologies that are key to us in the program at EPA. We will focus more specifically on some of those that would be of interest in each category, for example, the Lurgi/Fischer-Tropsch or methanol or other synthesis approach such as Mobil-M gasoline.

In essence we have three variations of commercial or near-commercial gasifier technology coupled with some synthesis approaches to give us some liquid products. And secondly, of course, we have the direct liquefaction processes, which most of you have been exposed to previously.

With respect to our overall implementation approach, we are using major contractors mainly because of limitations in manpower. We have major environmental assessment contractors that we rely on to do the work. We have underway various field studies that are keyed to the program, various critical experimental studies to provide data that are missing because really commercial facilities don't exist in many cases. We are trying to develop some well-defined output documents so that everybody understands what we are designing into these outputs and reports that we are going to be generating. It's got to be of interest and of use to the Agency and to industry with respect to what it can be used for. Also in this activity we have the need for close collaboration and support of our EPA program offices. This, after all, is our key role in life here.

The major EPA contractors for the three areas are TRW in the indirect and high-Btu area, Hittman in direct liquefaction, and Radian in the low- and medium-Btu gasification area. The first two, of course, are the ones that are primarily relevant to what we are talking about here today.

Table 2 lists relevant field studies in terms of being completed, active, or potential. Those that we have completed include some work at the Lurgi-Kosovo plant in Yugoslavia. The right side of the table outlines the kind of work we have done. We have done some work on the SRC-I test burn and SRC-II sampling and analysis at the Fort Lewis pilot plant. We are still active in the program at the Lurgi-Kosovo unit, doing Level 2 fugitive emissions sampling, wastewater treatability, etc., still working on the SRC, and trying to get started with the H-Coal work. Finally, the potential areas include Koppers-Totzek, Texaco, and Exxon Donor Solvent.

I think we're at a point where we are really going to depend a lot on what cooperation we can come up with to provide some progress in this area. We would like to solicit the support of those of you in industry who are involved with these systems, so that we can gather the data and develop some mutual understanding in terms of what will be meaningful control guidance.

Also important to the program are some critical experimental studies. A synfuels environmental center concept is being used constituted of a group of universities and the Research Triangle Institute, located near our Laboratory in North Carolina. Our resource allocation to them is dedicated to the creation of a center of expertise to work toward some environmental understanding in this area.

Experimental studies in pollutant screening are very important to us, as are studies of gas clean-up options for these systems, wastewater clean-up options, solid waste disposal, and combustion modifications testing to handle some of the fuels that will be products of the synfuel processes. Table 3 outlines objectives in the pollutant screening area.

Probably the most critical area is to identify, list, and determine the relative importance of pollutants from these processes so that we are looking at the right things relative to our development of guidance.

Another part of this center of activity on the environmental aspects of synfuels is a coal gasification clean-up facility which is aimed at determining the efficiencies of things like raw gas and acid gas clean-up. We are trying to focus on the fate of pollutants as a result of the application of clean-up systems to such processes and on characterization of the controlled discharges from these systems. We are comparing the alternatives; the bottom line here again is some engineering design criteria and cost bases for identifying the best control options.

Another part of the environmental center activity is focused on wastewater treatment. We are looking at evaluation of specific treatment systems. Table 4 lists the basic biological and physical/chemical approaches that one might transfer or apply to the types of waste, optimally from an environmental standpoint. We are starting out with some rather simple components and mixtures and then working toward some continued integrated evaluation. Maybe later on there will be some collaborative evaluation with interested parties on wastewaters from such systems.

We have done a bit of work on combustion characterization of the various synfuels, shown in Table 5. We have done some monitoring of an SRC-I full-scale test burn. In the SRC-II area we have done some experimental furnace studies, looking at things like what happens to the nitrogen from the standpoint of some fundamental combustion understanding with respect to NO_x control.

One accomplishment I might report here is the rich burn/quick quench stationary gas turbine combustor which we have developed at Pratt and Whitney. It seems to handle high-nitrogen fuels very effectively. It is now at a prototype stage but has handled such things as the SRC-II and high-nitrogen oil shale at NO_x levels substantially below the existing New Source Performance Standards for gas turbines.

We also looked at some Hydrocarbon Research coal-derived liquid fuel at the basic study level to see where we want to go with combustion mods for that type of fuel.

Most of the key reports related to environmental assessment have been mentioned previously. The standard support plans are designed to provide useful information for both the Agency and industry. The standard support plan compiles research in our own organization to provide a central source on what the various program offices are doing. It discusses legislative mandates and regulatory approaches in response to the regulatory mandates in the air, water, solid waste, toxic substances, and other program offices. It puts them together in some kind of a schedule and makes them compatible with some of the ORD support to this work, including the pollution control guidance document that has been referred to several times today.

The source test and evaluation report is specifically aimed at getting the data from a particular source test to everybody as fast as possible. In other words, as we go out and test a particular facility, we want to get these data into some kind of a report and make it available to whomever may need it.

The environmental assessment report has also been referred to previously. It tends to be a rather comprehensive compilation and development of the emissions and their characterization. It also includes some evaluation on a media-by-media basis and some discussion of the various options that may have an effect on those emissions that we characterize. It is really zeroed in on a particular process. For example, one might be developed for Lurgi SNG. It tends to be one of the most comprehensive data base reports that we have on a particular technology.

Table 6 is a schedule that indicates some of the key technology transfer reports. I will just mention a few of them. For example, the environmental assessment data base report on coal liquefaction, which is a very broad report containing really the whole data base that we have on coal liquefaction, was out in September of 1978. We have a source test and evaluation report on the Lurgi-Kosovo testing coming out this month.

We have two environmental assessment reports out already, the Lurgi and the SRC-I and II coal liquefaction environmental assessment reports. These are all seen as iterative-type reports. That is, as we develop data from testing and gather data from others that may be usable in these reports, they will tend to be enhanced and made more useful, I think.

The pollution control guidance document for indirect coal liquefaction is one of the key ones that we mentioned earlier. We are pushing very hard to get that out in draft form by September of 1980. However, that may not be the end of the line with respect to getting it out in a usable form. The direct liquefaction document is due in about the middle of 1981.

In another attempt to characterize the program, I can list some key program aspects. The environmental assessment methodology development has been of concern to us, as have identification of key pollutants, prioritization of the streams needing control, and pollution control technology evaluation, which includes guidance, design parameters, and cost estimates.

I would now like to lead in to a discussion of the environmental assessment methodology mentioned earlier. Figure 4 summarizes, in a very compressed form, the basic EA components. This includes gathering all the technology background that is available for a given area, performing the sampling and analysis and the emission characterizations, and developing some environmental goals, which is really developing a set of targets that we can judge by. You can't do much with respect to analysis of any system or emission or effluent unless you have something to judge by. These target values are needed to accomplish our next step, which would be the impact analysis. This impact analysis is focused on the effectiveness of control technology. That is, we are at this point not really trying to identify all of the things that are happening out in the environment to start with but trying to bring that back in a little bit closer to the process to get a more direct measure of the control effectiveness. We can finally use this in terms of control evaluations and this whole activity evolves toward synthesis, review, publishing, and reiteration. The final output is aimed at a better understanding of the problems and the existing control alternatives, and at a better definition of R&D needs.

Table 7 outlines EPA's phased EA approach. Level 1 is really a survey phase to ask whether there is a problem. Here you are not getting down to the nitty-gritty but doing things comprehensively by class. Results are semi-quantitative in terms of precision and accuracy. Level 2 really gets into a more detailed analysis of what causes the problem, and that gets more direct and compound-specific. Level 3 is really zeroed in on things that we need to be paying a lot of attention to and we start monitoring selected pollutants to see how they are doing with time and performing closer evaluations of control devices.

How do we interpret the data we get from activities such as this? I have summarized this into two approaches. With respect to the chemical analysis data, the first cut that we take is to use an index that we call discharge severity. It's a rather simple approach, based on concentrations found in the various streams that we may be looking at from pilot- or larger-scale facilities. We compare these or ratio them against target concentrations or goals for a list of pollutants of concern that keeps getting updated, so that we have new things found in our assessments put into it and somehow prioritize it. This we call our MEG list or Multimedia Environmental Goal list.

In the biological testing area we use the battery of bioassays mentioned earlier. The index that we use here is called Assigned Response Value. It's geared to the specific nature of the bioassay tied into the maximum applicable dose for that bioassay.

What we are really working toward here in the way of special benefits in an environmental methodology is a way to find pollutants in an orderly fashion, to compare waste streams on a multimedia basis in an orderly fashion, to compare potential effect endpoints in an orderly fashion, and to establish some rank order of control options. We must also correlate the chemical and biological test results from our comprehensive characterization. Some other advantages of this approach include the creation of a system that will allow us to compare technology and compare process variables in some very complex flow sheets. We can also examine the importance of some improved health and environmental data that we need to have feedback on. We would like to be able to quantify any environmental improvement on a unit cost control basis to guide design. You need to have some way of putting a common denominator into effect in terms of improvements that we are making.

To illustrate what we have done with some of the methodology, we will discuss a gasification case study. It was really a pilot study designed to help evaluate what we call Level 1 -- the first phase of our environmental assessment. We wanted to see how much meshing and cohesiveness we had in the various segments of our methodology and also indicate its advantages to those who may be utilizing it in our various contractor areas.

The specific objectives in the gasification case study were to characterize the discharges and waste streams, to evaluate this Level 1 analytical methodology capability, prioritize discharges, and identify what we call Level 2 analytical needs. The site that we used in this study, the Wilputte-Chapman gasifier, had a feedstock of bituminous coal. The reasons for selection of this particular facility were that it was commercial size, it was available for testing, it was a relatively simple system to start with, and it used bituminous coal, which meant that tars and other pollutants would be present to give us a little better test of our methodology.

Figure 5 is a flow sheet of the gasifier. The capacity of the system was about a thousand kilograms an hour, with a two-hour residence time at about 1900°F (1040°C). The quench was really a scrubber device that operated to clean the tars and other materials from the gas, and the tar liquor separator gave us a tar material. The spent quench liquor was potentially discharged to a forced evaporator. This evaporator was not in operation during our testing, so we don't have a sample here, but we did have some separator vent gas to look at.

The diamonds in the chart represent samples that we took in this characterization of the plant. Everywhere you see that we had some sample, an analysis was done. Table 8 is a summary of the samples and analyses taken that correspond to the diamonds on Figure 5.

The Level 2 chemical analysis, which is a more specific chemical analysis, was not done completely. It was done on our Level 1 sample. We didn't go back and gather a separate set of Level 2 samples, which would have been more comprehensive. This was limited to GC/MS analysis on those particular samples, so it was a partial approach. Level 2 would normally include more samples and additional analytical techniques.

Table 9 outlines the chemical categories that warrant some further analysis. The waste streams are listed across the top, starting on the left with the coal feeder vent. The value DS is the abbreviation for discharge severity mentioned earlier. The discharge severity, just to repeat, involves a ratio of the actual discharge concentration found to the target values which we call MEGs. The MEG categories cover all classes of compounds that could conceivably occur from fossil-energy type processes, with the specific compounds listed within the classes.

At this point, the categories listed are the ones, as I say, that were flagged. They are flagged on the basis of assuming that the total mass of the material in that category that's found in our chemical analysis is the most toxic compound in that category. So you are really using a screening approach at this point. It's not telling you any more than, "Hey, maybe there is something you ought to look at in that category. Go back and do some more analysis on it, if you have a discharge severity greater than one."

We also put in here for comparison some results from an RTI lab gasifier, which is a screening approach that I mentioned earlier. It looks at all kinds of fuels and reactor conditions and gives a very comprehensive look at all substances that may come from such systems. As you can see, there is fairly good correlation between the kinds of categories that may be of interest across the board, including the laboratory-scale gasifier.

In the bottom categories, such as the heterocyclics, it looks as if perhaps something is going on down there that we may want to take a closer look at, for example, Category 23, which is heterocyclic nitrogen compounds.

Figure 6 compares some of the bioassay and chemical results for two of the sources in that plant: the separator vent and the separator liquor. The main point of interest here is the similarity of results. There are also other cases in which either the bioassay or chemical results independently show a problem. Here they are both indicating that maybe you need to go further in identifying what you have present there. The assigned response values in the figure indicate some form of biological toxicity. The various bioassay tests are listed across the bottom, for example, Ames, WI-38, and RAM. Health and ecological tests are shown separately to get a picture of both aspects. Finally, on the right is the discharge severity. These are really total discharge severities summed up for the various compounds found in each of these streams and the number shown is really the log of the discharge severity. You really can't correlate the heights. It just shows that both chemical and biological testing approaches are telling you about the need to look a little further at those particular sources of emissions.

Table 10 shows how the methodology allows you to chop away at the problem a little bit without missing a whole lot. This is just for one emission source in this particular gasification plant -- the coal feeder vent. In this case, we are starting out with a raw sample with the potential of containing something like 26 different categories of organic compounds about which we may have concern, including about 650 separate pollutants. Going through our Level 1 phased approach involves specific analytical techniques such as liquid chromatography, infrared, and low-resolution mass spectrometry.

The unknowns are reduced to the point where at the end of Level 1 you are worried about something like 13 of these classes and about 135 substances. Then you jump down to Level 2, get more specific with your GC/MS, and reduce the concerned areas to about six categories and about 20 pollutants of concern.

It's worth noting here that you can't very well jump to the GC/MS and go ahead and get your analysis, because without some kind of a directed approach you have to ask yourself, "Well, where does one stop in terms of the time or expense to find out what to analyze for?" The question is whether we have an analytical capability to just go out and analyze everything for everything.

Table 11 is another example of priority compounds in the separator vent gas. It shows in particular the ones of concern at a Level 2 analysis with a discharge severity greater than one. The MEG category, the compound, and the potential endpoint on the right-hand side beg the question -- how much are you really going to have there and how it can be controlled?

As a result of all this, we did some effluent stream ranking for further evaluation from that plant. The order of these for this facility was as follows: separator vent, coal feeder vent, by-product tar, gasifier ash, and cyclone dust. This was actually done using weighted values. We multiplied the discharge severity for each waste stream by its mass flow rate so the resulting weighted values could be directly compared and then factored in the bioassay results. The results indicate that we need to look first at that separator vent to see what problems we might be able to rectify there.

We didn't have much in the way of control technology hooked into this plant but we asked ourselves, for the problems that we identified in the order of priority, what would be some potential sources that we would want to eventually recommend for further exploration. Table 12 outlines potential control techniques. For example, coal feeder vent gas might be handled with scrubbers plus incineration, or recycling the stream back into the gasifier. Certain discharges may require some kind of special disposal. I might note in passing that heretofore, the first two items, the coal feeder vent stream and the separator vent, were not even recognized as control needs in terms of their relative importance.

A final topic of discussion is just what would we would do with these results. As shown in Table 13, they would be valuable to us directly for planning our Level 2 and 3 sampling and analyses and control evaluations. They would be incorporated into the source test and evaluation report, be input to the pollution control guidance document, and disseminated to the regional offices. We are eventually working toward such goals as a better definition of review criteria for permit applications.

James O'Hara, Ralph M. Parsons Company: Would you elaborate on this rich burn/quick quench procedure and its effectiveness in handling the high-nitrogen fuels?

Mr. Hangebrauck: So far our testing has just had one go-around on this. We were originally looking at the lower nitrogen fuels just trying to do a better job with the dry control system rather than using water injection as an approach, primarily in order to lower emissions and avoid that energy loss associated with wet injection. But the tests on, say, the SRC material and oil shale, which have a substantial percentage of nitrogen in the fuels, showed results that were significantly below the existing NSPS for gas turbines, which is something like 125 ppm for higher-nitrogen fuels.

We are at a stage in the development where this prototype burner has been operated as a single combustor. The next stage is really some kind of a demonstration that would incorporate this into some existing engine designs. We hope to start out with smaller turbine work and then maybe move on to something a little bigger. Right now we are unsure about how far we can take this because of funding priorities.

Norbert Jaworski, EPA: It doesn't give you any problems with carbon monoxide and hydrocarbons?

Mr. Hangebrauck: The overall emissions from the system look real good, compared to what we are normally talking about -- CO less than 100 ppm and hydrocarbons less than 5 ppm.

Fred Glaser, DOE: When he was discussing the President's program, Frank mentioned the emphasis on indirect liquefaction and its projected capacity to the 1990s. I am looking at your environmental assessment report schedule and I notice that you hope to get one out on indirect liquefaction in mid-1981. I guess there are some other standards that aren't quite defined at this point either. Do you feel that that schedule may impact adversely on the private sector interest for a domestic indirect liquefaction industry?

Mr. Hangebrauck: No, I would think maybe just the opposite. The one on indirect liquefaction that we were talking about is due in draft in September 1980. We are working on that right now, of course. I think that by putting together information as we go along on this area and bringing in the EPA program office development of the various parts of this document, we are probably on a fast-track approach.

I think that it is probably going to be a real boon to the people who want to do something in this area because it will be an ongoing activity and we will have some kind of spinoff as we go along. Key people will be working on it. So I think it should be our best bet really to make some impact and clear away some of the potential problems.

Sid Thomson, Fluor, Inc.: I agree with Bob. With a forum like this, with information being available, and with knowledge of the pollutants, some of the moving targets can be eliminated.

Mr. Princiotta: Your point was that we are a little bit late in getting this document published.

Mr. Glaser: Looking at the schedule, it's coming down. In fact, it's September 1980 but the SRCs, of course, already exist.

I realize that you have demonstration plants and pilot plants to base your assessments on with respect to the indirect liquefaction. There is nothing really much in the United States, although I know you have SASOL tests.

Mr. Princiotta: Quite frankly, prior to the last six months, we had designed our synthetic fuel program to complement the DOE program, which had by and large decided it would concentrate on direct processes. We are caught a little flat-footed with all this emerging interest in a technology that has been around for the last 20 or 30 years. We are very interested really in industrial input, and for that matter DOE input, as to whether these indirect liquefaction processes will really be important in the 1990 to 1995 time frame. New conventional wisdom seems to suggest this is the case, but one of our major goals in this meeting is to try to sort out all our priorities.

Mr. Hangebrauck: Luckily, a lot of what we have done may very well be applicable to this area. For example, work is being done at North Carolina State on the gasifier clean-up systems. We are looking at things like the methanol absorption of acid gas, or something resembling the Rectisol process, and some of the problems resolved there may help us to get along fairly rapidly.

Barnet Groten, Texas Eastern Corporation: I have no doubt that the indirect technologies

TABLE 1. KEY TECHNOLOGIES IN EPA'S ENVIRONMENTAL PROGRAM FOR COAL LIQUEFACTION

- INDIRECT LIQUEFACTION
  - LURGI/FISCHER-TROPSCH OR METHANOL OR METHANOL-MOBIL M
  - KOPPERS-TOTZEK/FISCHER-TROPSCH OR METHANOL OR METHANOL-MOBIL M
  - TEXACO/FISCHER-TROPSCH OR METHANOL OR METHANOL-MOBIL M
- DIRECT LIQUEFACTION
  - SRC I & II
  - H-COAL
  - EXXON DONOR SOLVENT

TABLE 2. RELEVANT EPA FIELD STUDIES

COMPLETED	●	LURGI-KOSOVO	-	LEVEL 1 AMBIENT MONITORING
	●	SRC I - TEST BURN	-	MITCHELL
	●	SRC II	-	FT. LEWIS PILOT PLANT
ACTIVE	●	LURGI-KOSOVO	-	LEVEL 2 FUGITIVE EMISSIONS
			-	WASTEWATER TREATABILITY
			-	PHENOSOLVAN--REEVALUATION
	●	SRC I & II	-	FT. LEWIS PILOT PLANT
	●	H-COAL	-	KENTUCKY
POTENTIAL	●	KOPPERS-TOTZEK	-	MODDERFONTEIN S.A.
	●	TEXACO	-	TVA & SO. CALIFORNIA
	●	EXXON DONOR SOLVENT		
	●	METHANOL/MOBIL-M/GASOLINE		
	●	LURGI/FISCHER-TROPSCH (SASOL)		

TABLE 3. OBJECTIVES IN POLLUTANT SCREENING

- POLLUTANTS VS COAL TYPES
- POLLUTANTS VS OPERATING CONDITIONS
- RATE OF POLLUTANT FORMATION
- EVALUATION OF TEST RESULTS
  - CHEMICAL
  - BIOASSAYS
- IDENTIFY, LIST, AND DETERMINE RELATIVE IMPORTANCE OF POLLUTANTS FROM SYNFUEL PROCESSING
- DETERMINE MEANS FOR PREVENTING POLLUTANT FORMATION

TABLE 4. BASIC APPROACHES TO WASTEWATER TREATMENT

- EVALUATION OF SPECIFIC TREATMENT SYSTEM
  - BIOLOGICAL TREATMENT
  - COAGULATION
  - FLOTATION
  - ADSORPTION
  - OZONATION
  - MEMBRANE SEPARATION
- CONTINUOUS INTEGRATED BENCH EVALUATION
- COLLABORATIVE EVALUATION OF WASTEWATER

TABLE 5. COMBUSTION CHARACTERIZATION OF SYNFUELS

- SRC I
  - MONITORED FULL SCALE TEST BURN
- SRC II
  - BASIC STUDIES
  - EXPERIMENTAL FURNACE STUDIES
  - RICH BURN/QUICK QUENCH STATIONARY GAS TURBINE COMBUSTOR TEST
- HYDROCARBON RESEARCH COAL-DERIVED LIQUID FUEL BLEND
  - BASIC STUDIES

TABLE 6. STATUS OF TECHNOLOGY TRANSFER REPORTS

STANDARD SUPPORT PLAN	
● SYNTHETIC FUELS FROM COAL (DRAFT)	5/79
ENVIRONMENTAL ASSESSMENT: DATA BASE REPORT	
● COAL LIQUEFACTION	9/78
ENVIRONMENTAL ASSESSMENT: SOURCE TEST & EVALUATION REPORT	
● LURGI - MED BTU KOSOVO	
- PHASE I	10/79
- PHASE II	4/80
- FUGITIVE EMISSIONS	4/80
- AMBIENT MONITORING (ESRL)	12/79
● SRC I AND II LIQUEFACTION - FT. LEWIS	12/79
ENVIRONMENTAL ASSESSMENT REPORT	
● LURGI COAL GASIFICATION FOR SNG	7/79
● SRC I & II COAL LIQUEFACTION	9/79
POLLUTION CONTROL GUIDANCE REPORT	
● INDIRECT COAL LIQUEFACTION - FISCHER TROPSCH/ METHANOL/GASOLINE	9/80
● DIRECT LIQUEFACTION	6/81

TABLE 7. EPA'S PHASED APPROACH TO ENVIRONMENTAL ASSESSMENT

- LEVEL 1: SURVEY PHASE (IS THERE A PROBLEM?)
  - COMPREHENSIVE
  - CLASS RESOLUTION
  - SEMIQUANTITATIVE
- LEVEL 2: DETAILED ANALYSIS PHASE (WHAT CAUSES THE PROBLEM?)
  - DIRECTED
  - COMPOUND SPECIFIC
  - CONFIRMATORY AND QUANTITATIVE
- LEVEL 3: MONITORING OF SELECTED POLLUTANTS (TEMPORAL VARIATION)
  - VARIATION WITH TIME AND CONDITIONS
  - OFTEN SIMULTANEOUS WITH CONTROL DEVICE EVALUATION

TABLE 8. SUMMARY OF GASIFIER SAMPLES AND ANALYSES

	MAJOR CONSTITUENTS	LEVEL 1 CHEM & BIOASSAY	LEVEL 2 CHEMICAL ORGANIC
COAL FEED	X		
COAL FEEDER VENT GAS		X	X
GASIFIER ASH	X	X	X
CYCLONE DUST	X	X	X
SEPARATOR VENT GAS		X	X
BY-PRODUCT TAR		X	X
SEPARATOR LIQUOR		X	X
RAW PRODUCT GAS	X		
CLEAN PRODUCT GAS	X		

TABLE 9. CHEMICAL CATEGORIES WARRANTING FURTHER ANALYSIS AFTER PRELIMINARY GASIFIER TESTING

ORGANIC CATEGORIES DS >1 (EFFLUENT)

	CASE STUDY				RTI
MEG CATEGORIES	COAL FEEDER	SEPARATOR VENT	BY-PRODUCT TAR	SEPARATOR LIQUOR	LAB GASIFIER
1. ALIPHATIC	X	X	X		X
2. ALKYL HALIDES		X	X		
6. GLYCOLS, EPOXIDES				X	
8. NITRILES	X	X	X		
10. AMINES	X	X	X		X
13. THIOLS, SULFIDES, DISULFIDES	X			X	X
14. SULFONIC ACIDS, SULFOXIDES	X				
15. BENZENE, SUBSTITUTED BENZENE	X		X		X
18. PHENOLS	X	X	X	X	X
21. FUSED POLYCYCLIC	X	X	X	X	X
23. HETEROCYCLIC NITROGEN	X	X	X	X	X
24. HETEROCYCLIC OXYGEN	X	X	X	X	X
25. HETEROCYCLIC SULFUR	X	X	X	X	X

TABLE 10. REDUCTION OF UNKNOWNS VIA TIERED APPROACH: COAL FEEDER VENT ORGANICS

		LEVEL 1			LEVEL 2
	RAW SAMPLE	LC	IR	LRMS	GCMS
NUMBER OF IDENTIFIED CATEGORIES	26	24	14	13	6
NUMBER OF POLLUTANTS OF CONCERN	650	355	225	135	20

TABLE 11. PRIORITY COMPOUNDS IN THE SEPARATOR VENT GAS

LEVEL 2 ORGANIC COMPOUNDS
IDENTIFIED: SEPARATOR VENT (DS >1)

MEG CATEGORIES	COMPOUND	POTENTIAL BIOLOGICAL EFFECT
8.	ADIPATIC ESTERS PHTHALIC ESTERS	TOXIC (LOW) TERATOGENIC
10.	AMINOTOLUENE	CARCINOGENIC
15.	INDENE	CARCINOGENIC (SKIN)
18.	PHENOL CRESOL	TOXIC, CARCINOGENIC TOXIC
21.	NAPHTHALENE	CARCINOGENIC

TABLE 12. POTENTIAL GASIFIER CONTROL TECHNIQUES

- COAL FEEDER VENT STREAM
  - SCRUBBERS WITH INCINERATON
  - RECYCLING STREAM INTO GASIFIER
- SEPARATOR VENT STREAM
  - SCRUBBERS WITH INCINERATION
  - RECYCLING STREAM INTO GASIFIER
  - VENT INTO PRODUCT GAS
- SEPARATOR TAR TOXIC MATERIAL HANDLING
- SEPARATOR LIQUOR - CONVENTIONAL TREATMENT
- GASIFIER ASH - MAY REQUIRE SPECIAL DISPOSAL
- CYCLONE DUST - MAY REQUIRE SPECIAL DISPOSAL
- POKE HOLES - WILL REQUIRE POSITIVE CONTROL SIMILAR TO COAL FEEDER VENTS

TABLE 13. USE OF RESULTS

- TEST PLAN FOR LEVELS 2, 3
  - ADDITIONAL SAMPLES AND ANALYSES
  - CONTROL EVALUATIONS
- TECHNOLOGY TRANSFER
  - EA:STER - ORD
  - INPUT TO PCGD - REGIONAL OFFICES, COMMERCIALIZATION
  - INPUT TO EAR - PROGRAM OFFICES, DOE, DEVELOPERS
- RECOMMENDATIONS TO:
  - DOE
  - FACILITY OWNERS
  - PROCESS DESIGNERS

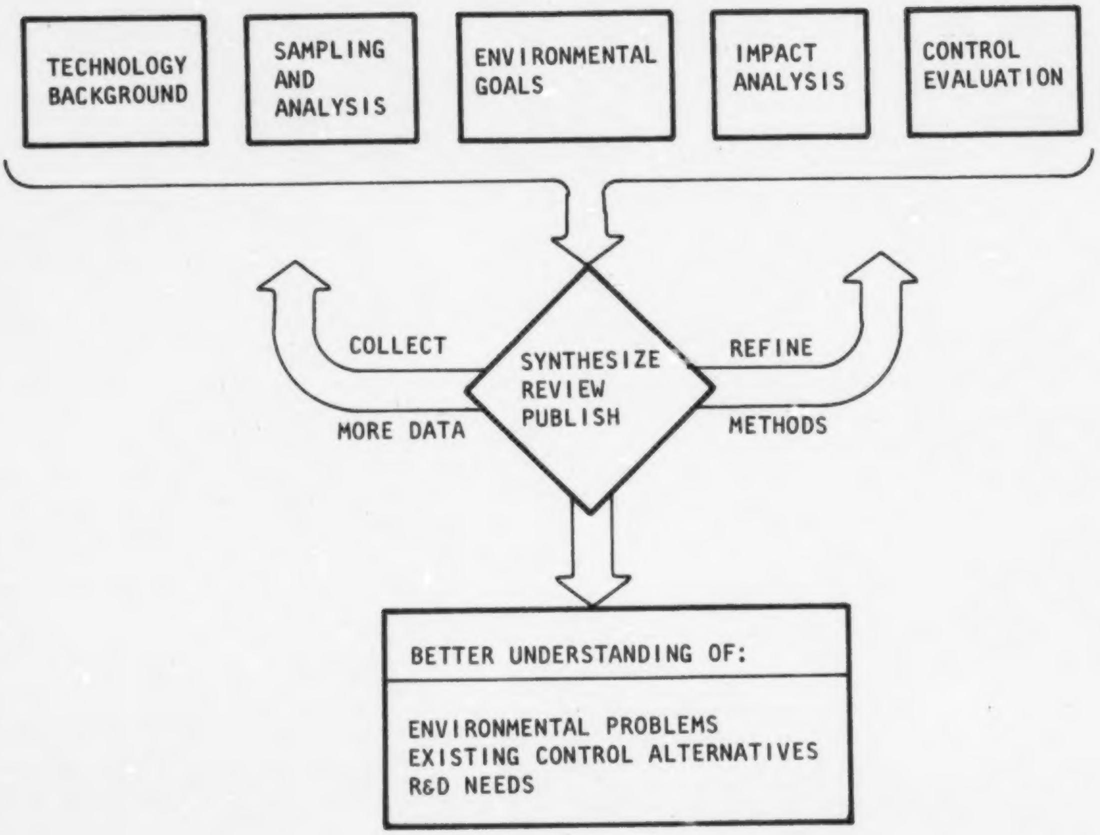
TECHNOLOGY BACKGROUND
SAMPLING AND ANALYSIS
ENVIRONMENTAL GOALS
IMPACT ANALYSIS
CONTROL EVALUATION
COLLECT
MORE DATA
SYNTHESIZE
REVIEW
PUBLISH
REFINE
METHODS
BETTER UNDERSTANDING OF:
ENVIRONMENTAL PROBLEMS
EXISTING CONTROL ALTERNATIVES
R&D NEEDS

Figure 4. Basic Components of an Environmental Assessment

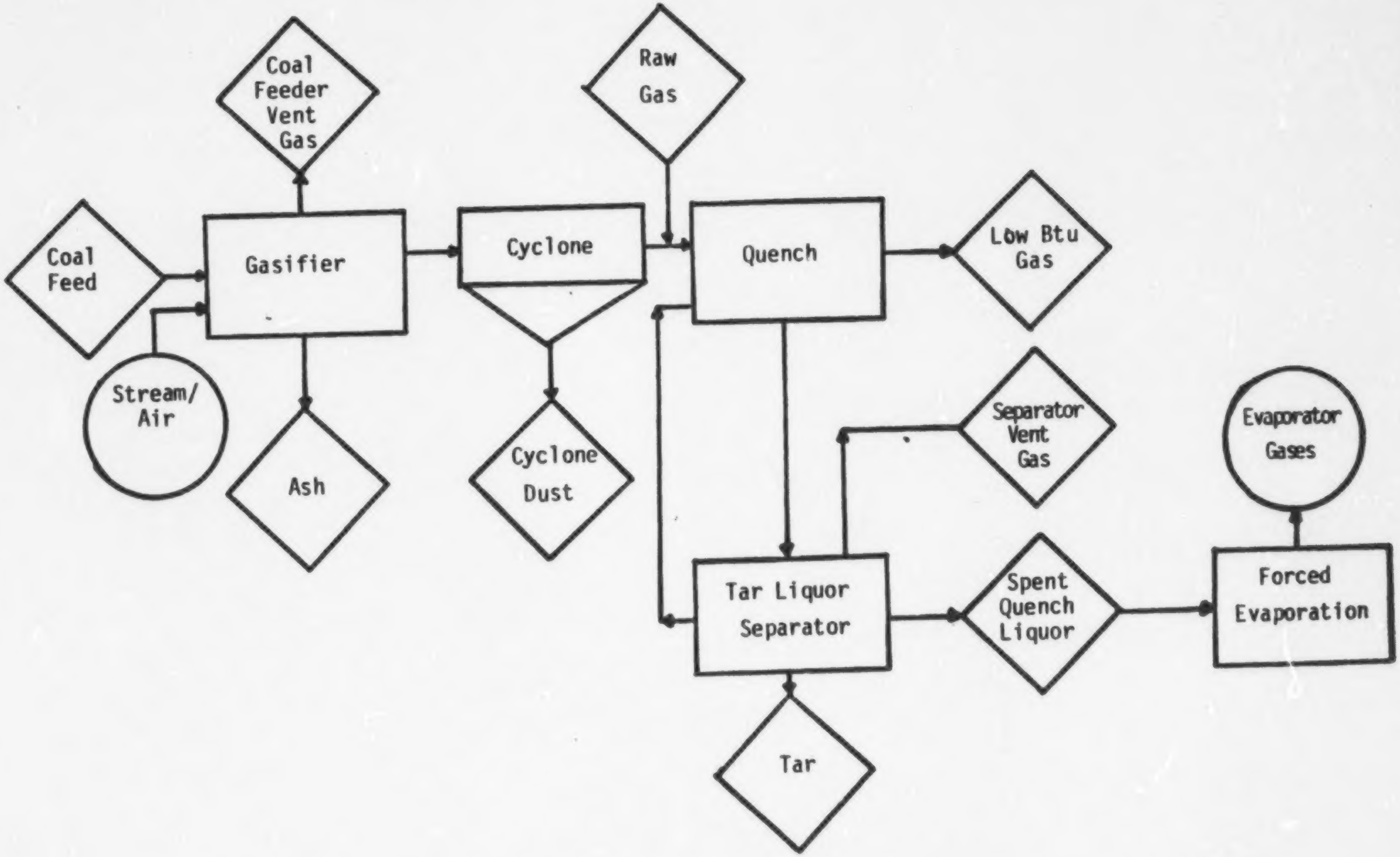
Coal Feeder Vent Gas
Raw Gas
Coal Feed
Gasifier
Cyclone
Quench
Low Btu Gas
Stream/ Air
Ash
Cyclone Dust
Separator Vent Gas
Evaporator Gases
Tar Liquor Separator
Spent Quench Liquor
Forced Evaporation
Tar

Figure 5. Flow Diagram, Wilputte-Chapman Gasifier

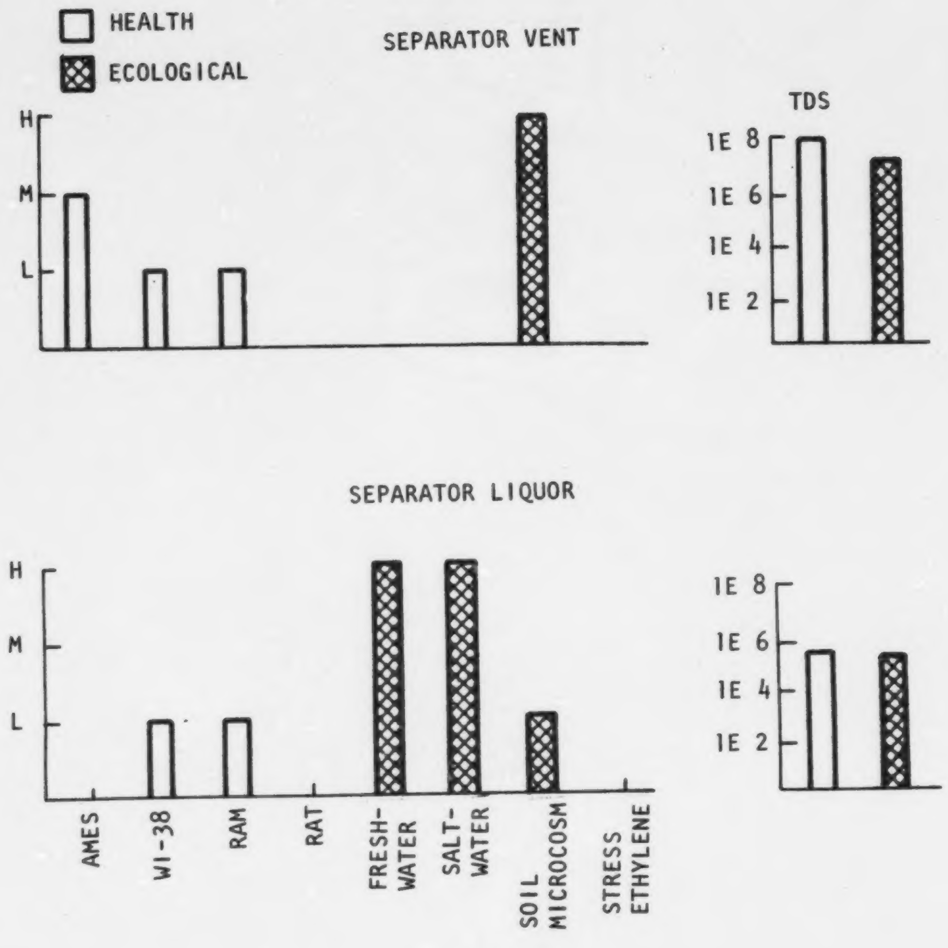

Figure 6. Comparison of Bioassay and Chemical Results for Separator Vent and Separator Liquor

will be a significant part of any synfuels industry early on. Whether it's based on that will eventually be seen. Secondly, we have had experience with the SASOL people and climbed around just about all of the working gasifiers in these areas.

One of the things which you don't hear much about is that in a real-world situation no large-process industry plant stays constant for any length of time. It's not a laboratory situation in any plant that's been going for a number of years. You find all variations from a Mark I to a Mark V version of something, whether it's a seal, a valve, or an operational procedure. The procedures as well as the hardware differ in small details. Although they are all Lurgis, you wouldn't recognize one by looking at another.

In terms of the evolutionary changes that have been made, which are normal in any large process plant, as operators learn to do things they do them a certain way. In some cases operators learn to expedite things. We all know that there are corners cut, depending on production schedules and the like. They vary from one place to another and in any given place from one time to another.

It's extremely difficult to get a set of data. I would frankly find it impossible. This is what these Lurgi gasifiers are going to do universally and I have to agree with the comments of the DOE gentleman here. I think we are in a bit of a bind if the indirect technologies are going to come on near the end of the synthetic fuels program. I am really at a loss to know where we are going to get any significant information within the time frame. That seems to be evolving from what's coming down off the Hill.

I would like your thoughts on what type of steps can be taken to either backfill the immediate situation or to start a program later on.

Mr. Hangebrauck: I would have to agree with what you are saying. I guess our approach to this whole business is to try and identify those ways that we have of getting some kind of information. I tend to be oriented toward facilities that are available to us or we are trying to get access to. For example, the SASOL people themselves have been of much interest to us in terms of trying to establish some closer involvement and data gathering with respect to that plant in South Africa.

But we also could use whatever information is available from any industrial group here that may be focusing on this area. Perhaps some of you have some prior or ongoing experience in designs and in some of the glitches that may be being solved.

In some cases I think we are just going to have to substitute some smaller-scale approaches to environmental control. Maybe one answer is to make up time through application of some slipstream-type control devices or smaller-scale solid waste treatment evaluations to really determine what is appropriate. So I think it's really just a question of putting together what we can do in the limited time we have available.

Mr. Princiotta: I wonder if I could add something to that, Bob. In the time frame we are talking about, 1981, for getting out the pollution control guidance documents, I think quite frankly there will be little time for generating much new data. I hope there will be some time. I hope we can crash and get whatever data are out there but I am personally a little skeptical that we are going to find that much data, particularly on control sources. What we are really looking for are well-controlled gasifiers and liquefiers and we will be lucky to get on any gasification-liquefaction unit, let alone one that has all the proper controls.

That particular low-Btu gasifier, you might have noticed, had no sulfur controls at all, to give you an example of what's out there. For that reason, we may have to resort to engineering approaches, paper studies that take what we know about the given energy technology and apply technology from other industries, in a paper-design fashion. I cite the example of that Lurgi report because that might be a kissing cousin of a pollution control guidance document, which essentially is based on very limited information. Let's take the old flow sheets from a given system, in this case, a Lurgi gasifier. Let's apply known controls. Let's make some assumptions as to how the controls will work on these particular energy systems and then calculate costs and come up with some recommended control levels.

I think that is less than satisfying to many of you. We would like to get your nitty-gritty response to an approach like that because, quite frankly, I don't think there is any way around those kinds of engineering studies if we are serious about getting out any control technology guidance or even standards, for that matter, in the next two or three years.

The plants are just not out there nor are those out there controlled to the levels we are talking about. So we are really anxious for your reaction to that kind of approach.

Kelly Janes, EPA: I have a comment. You are correct; we are not in a position to identify the emissions and quantify the characteristics of those emissions for any particular system, whether it's Lurgi or Koppers-Totzek or Texaco. What we try to do initially is identify potential types of emissions or discharges and identify the potential environmental problems. In that way the designers can then take them into account.

A lot of these probably are not applicable to a better environmental plan but still they can be very easily overlooked. It is important to characterize your very low-volume emissions, which can be very toxic if they contain PNA and those types of materials. We think our first priority is to identify the types of emissions you can run into and the potential problems.

Now, whether that applies to your plant or somebody else's will be determined later, but it is a guideline. You can look at the data and say, "Yes, I don't want that type of emission or I don't want that type of a system." The charging system for Lurgi and the pressure from the lock hopper are fairly large sources of potential problems in the system, and there are other methods of getting around it outside of exhausting into the air.

Mr. Hangebrauck: Regardless of this short-term approach, we do want to look downstream to plan ahead with various agencies and industries involved with development and demonstration of these systems. In that way we will all understand what are the right data to be collecting and whether it will be useful for purposes that we have in mind with respect to defining a good regulatory approach. That will take a lot of planning, I think.

Mr. Thomson: Will the raw data be available to industry? By that I mean before it's screened by the contractor and he has made his analysis of the situation. After that time, will EPA have the raw data from which the contractor has made his supposition?

Mr. Hangebrauck: Sure. I think this is going to be the case. There may be individual situations that warrant some particular care and use of that data, depending on the interest involved in the development. The source test and evaluation report I mentioned is going to be the most helpful document along those lines. That is, after we have done a test on a particular facility, we can go ahead and release the data. It will appear pretty much comprehensively in that report and you can use it the way you want to use it at that point.

Mr. Janes: As you know, what we sample, how we sample it, and the analytical results are included in the report itself. There are no other data that I know of.

Mr. Princiotta: I think he is asking though, for raw data before any massaging from the contractor.

Mr. Janes: The raw data are in the appendix in the report. It's about as raw as you can get.

Mr. Thomson: I don't want it published, so to speak, but I want it available in your files. In other words, when a contractor does a job for you, to me there ought to be back-up raw data that somebody else can have a look at if they so desire. On so many of the reports when I tried tracking down the basis for a supposition, I found I can't get that information.

Mr. Hangebrauck: Yes. Quite often.

Mr. Thomson: I have asked EPA. Quite honestly they have told me, "Well, we haven't been able to get the contractor to give us that information."

Mr. Jaworski: One other thing we have is the environmental assessment data base that is being used now. I don't know if it includes all the raw data but it's a beautifully computerized system and it will include all data that can be logically put into a system.

Mr. Hangebrauck: That is something I did not mention. It would be a fairly expensive data system to access. I don't really think there is going to be a problem of access unless there are cases where there are limitations that somebody would place on the data.

Mr. Thomson: That's what I was curious about.

Mr. Jaworski: I think one thing Bob alluded to is our testing of various systems and what we have done with RTI. You really haven't gone across the spectrum and really identified anything significantly different from the field tests and the lab tests. Do you want to comment a little bit on that?

Mr. Hangebrauck: Yes. It was reflected somewhat in Table 9. It compared some of the compound classes that were being identified from various sources on this particular gasifier to the micro-scale kind of conversion system at RTI. There was a great deal of similarity. You see the same kinds of groups of pollutants there. They may be there at overall different levels but there are great similarities in the types.

Mr. Jaworski: What that really translates into when we go into full scale is that we don't expect, based on what we have done in the pilot level and bench levels, to get a basically different scale in terms of pollutants.

There might be different concentration shifts when we run various scenarios on our gasifiers in terms of temperature, pressures, operating parameters, and feedstocks.

Mr. Princiotta then introduced Robert C. Green of Exxon Research and Engineering Company.

Exxon Plans in the Area of Coal Liquefaction: Robert C. Green, Exxon Research and Engineering Company.

This morning I would like to describe the status of the development of the Exxon Donor Solvent (EDS) coal liquefaction process. My presentation will begin with a brief description of the EDS process and a discussion of the project status, including a description of the progress in the construction of the 250 ton-per-day pilot plant. I will follow this with a description of coal feed flexibility and cover some of the environmental effects we predict for a commercial EDS plant. Finally, I will cover the outlook for commercialization.

The goal of the EDS coal liquefaction project is to develop the process to a state of commercial readiness. This means that the technology should be available at the end of the project to design and build a full-scale, pioneer commercial plant with a reasonable and acceptable level of risk.

In the EDS process development, bench-scale research, operation of small pilot units, and engineering design and technology studies are being integrated with operation of a 250 ton-per-day pilot plant.

The process sequence shown in Figure 7 is designed to maximize liquid products. The feed coal is crushed, dried, and slurried with hydrogenated recycle solvent (the donor solvent) and fed to the liquefaction reactor in a mixture with gaseous hydrogen. Reactor operating conditions are 800 to 900°F and about 2,000 psi total pressure. The reactor effluent is separated by distillation into a recycle solvent depleted of its donor hydrogen, light hydrocarbon gases, C_4-1,000°F distillate, and a heavy vacuum bottoms stream containing 1,000°F+ liquids, unconverted coal, and coal mineral matter. The recycle solvent is hydrogenated in a conventional fixed-bed catalytic reactor employing "off-the-shelf" hydrotreating catalysts.

The heavy vacuum bottoms stream is fed to a FLEXICOKING* unit with air and steam to produce additional distilled liquid products and a low-Btu fuel gas for process furnaces. FLEXICOKING is a commercial petroleum process that employs an integrated coking/gasification sequence in circulating fluidized beds. This process is operated at low pressures (~50 psi) and intermediate temperatures (900 to 1,200°F in the coker and 1,500 to 1,800°F in the gasifier). Essentially all organic material in the vacuum bottoms fed to FLEXICOKING is recovered as liquid product or combustible gases. A small amount of residual carbon is rejected with the ash from the gasifier fludized bed.

Process hydrogen is produced by steam reforming light hydrocarbon gases. An alternative method for hydrogen production which is receiving increased attention is partial oxidation of the heavy vacuum bottoms stream or of coal.

The total liquid product is a blend of streams from liquefaction and FLEXICOKING. Product utilization studies indicate that the 350°F- fraction should be used in gasoline/petrochemical manufacture and the 350°F+ fraction in fuel oil applications. The latter fraction from Illinois No. 6 coal contains about 0.6 weight-percent sulfur and about 0.8 weight-percent nitrogen. These levels can be reduced further by subsequent treating, if needed, to meet emissions standards.

Exxon Research and Engineering Company (ER&E) has been engaged in coal liquefaction research since 1966. The jointly funded research and development project started in 1976 and is in the fourth year of a 6-1/2 year program. DOE is providing 50 percent of the funding; the remaining 50 percent is being provided by the Carter Oil Company (an Exxon affiliate), Electric Power Research Institute (EPRI), Japan Coal Liquefaction Development Company (JCLD), Phillips Petroleum Company, Atlantic Richfield Company, and Ruhrkohle AG.

A broad technical program on the liquefaction portion of the process is being advanced essentially on schedule. The program on vacuum bottoms processing has been expanded to plan the operation of a 70 ton-per-day FLEXICOKING prototype at Baytown, Texas, using the vacuum bottoms produced from the 250 ton-per-day liquefaction pilot plant. This addition to the program is now under consideration by the sponsors.

The construction of the 250 ton-per-day pilot plant is proceeding. Figure 8 shows an artist's conception of the completed plant with details of the relative position of the administration building, the coal preparation facilities, the process area, and the product tankage areas. The estimated cost for the completed plant is $113 million, compared with the initial estimate of $110 million.

As shown in Figure 9, construction is expected to be completed in February 1980, compared with the original schedule of January 1. An increased engineering workload and an unusually wet spring in the Baytown, Texas, area have resulted in an extension of construction activities and slower construction progress.

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*Service mark.

Startup activities began this summer as sections of the plant were completed. Coal-in operations are expected by March 1980. Operation on three feed coals is then planned -- 15 months on the first coal, which will be an Illinois No. 6 bituminous coal, and six months each on two other coals. These coals have not yet been selected.

The operations of the 250 ton-per-day pilot plant are designed to demonstrate the operability of the EDS liquefaction section and obtain the scale-up data required for design of a commercial facility. Key objectives are demonstration of unit operability, design data acquisition, product yield and quality confirmation, and testing and production of feeds for demonstration of environmental controls. The EDS process can be applied to a wide variety of coal types including bituminous, subbituminous, and lignites. The younger subbituminous coals and lignites are, however, more difficult to process.

The overall process yields, which include liquids from both liquefaction and FLEXICOKING, are shown in Figure 10 at the preferred conditions for project coals. The bituminous coals give total liquid yields in the 43 to 45 percent range, the subbituminous coal produces about 40 percent liquid, and the lignite produces 35 percent liquid. Yields have the potential for being increased using process improvements currently under investigation. It should be noted that the liquids recovered from FLEXICOKING for the Burning Star coal have been higher than for any other coal studied.

Environmental control is important in the EDS plant itself, in the surrounding community, and also in the ultimate usage of the liquid products. As a part of the development program, we have sampled streams from our small pilot plants and used this information in our engineering studies to predict the plant emissions.

The EDS processing steps are extensions of existing coal and petroleum refining technology. Thus, the emission would be expected to be similar to coal-fired utility plants and petroleum refineries. Commercial design studies have indicated that 10 to 15 percent of the commercial plant's cost would be for emission control.

The expected atmospheric emissions for a commercial EDS plant feeding 30,000 tons per day of an Illinois No. 6 coal are shown in Table 14. These values are based on a recently completed study design update. Included are annual rates of about 6,000 tons of sulfur oxides, 740 tons of carbon monoxide, 3,200 tons of nitrogen oxides, 525 tons of particulate matter, and 1,575 tons of hydrocarbons.

Emission rates for all the criteria pollutants significantly exceed 100 tons per year, which is the threshold for definition as a major source. Offsetting reductions in emissions from other sources would be required to locate an EDS plant in areas classified as in nonattainment of national air quality standards. This essentially precludes construction of an EDS plant in a nonattainment area.

Table 15 shows the results of dispersion model calculations of the impact on ambient air quality of an EDS plant compared to the national ambient air quality standards. The critical GLCs for all pollutants from continuous sources are below the current EPA ambient standard. Thus, an EDS plant could be located in a Class II attainment area having meteorological conditions typical of Southern Illinois. A conservative buffer zone of 10 miles between the plant and Class I areas (national parks) would ensure that Class I Prevention of Significant Deterioration (PSD) increments would not be exceeded. The impact of the EDS plant relative to PSD requirements must be determined by air dispersion modeling after a specific plant location has been selected.

Table 16 gives an analysis of the wastewater stream after stripping and phenol extraction, but before treating from an EDS plant feeding 30,000 tons per day of an Illinois No. 6 bituminous coal. The wastewater treating scheme included in the study design update is based on the "Best Available Technology" to control the water pollutants found in the small pilot plant water samples. In addition to sour water stripping and phenol extraction are the steps of dissolved air flotation, biological oxidation, filtration, and activated carbon treatment. Approximately 60 percent of the treated water is reused as cooling tower makeup, with the remainder being discharged. The treatment scheme proposed is predicted to meet existing Illinois effluent standards, based on laboratory simulations of the individual steps.

Leaching steps have been carried out on solid wastes obtained from runs on both Illinois and Wyoming coal EDS bottoms in our small FLEXICOKING pilot plant. Table 17 shows the results of the extraction tests using the 12/12/78 EPA toxicant extraction procedure. All of the analyses are below the limit shown, which is 10 times the EPA primary drinking water standard. Barium and lead are the closest values, being about 60 percent of the standard. The "less than" values represent the limit of detection and consequently may not be significant. The FLEXICOKING solid wastes would appear to meet the non-toxic criteria specified in the 12/18/78 draft RCRA regulations.

Turning now to the environmental effects of the utilization of products from the EDS process, Table 18 compares particulate and NO_x emissions for two fuel oils produced from Illinois No. 6 coal with those from low-sulfur and regular-sulfur petroleum fuel oils. The combustion tests were carried out in a 50-hp Cleaver-Brooks Firetube package boiler.

Particulate emissions are very low from either coal liquid fuel. The regular sulfur fuel is actually more typical of a conventional heavy fuel. You can see it gives 4 to 5 times as much particulate emissions as the coal liquids and is close to the current New Source Performance Standards for power generation boilers of about 0.05 weight-percent (0.03 lb/MBtu). NO_x emissions are higher for the EDS fuel oil, reflecting the fuel's higher nitrogen content. All values shown are above the current New Source Performance Standard for coal liquids-fired utility boilers, which is about 350 ppm (0.5 lb NO_x/MBtu). Some NO_x control may be required, such as combustion modifications.

Commercializaton of the EDS process could start after the operation of the larger pilot plants in the 1980 to 1982 time period. Assuming sponsor approval of the FLEXICOKING prototype program, a design basis for an EDS pioneer plant could be available in 1982. Assuming a three-year design and engineering effort, construction of a pioneer plant could start in 1985 and start-up operations could begin in 1988 or 1989. Current estimates place the cost of a pioneer plant capable of processing 13,000 tons of coal per day at around $1.5 billion (1979 dollars). Such a plant would be one train of a commercial plant and would produce 25,000 to 30,000 barrels of coal liquids per day. It would be designed for later expansion to twice the size by the addition of a second process train, if and when justified.

Design of commercial plants might start after the pioneer plant operates for a year. In the case of the illustrated development schedule for the EDS coal liquefaction process, this could mean 1989, and construction could begin in 1992 with start-up in 1997.

Of course, a synthetic fuels industry will not develop in the private sector unless there is an expectation of a reasonable return on investment. In the mid-1980s, the return for a coal liquids project will probably be too low to attract private investment. The price of hydrocarbon liquids will need to increase substantially compared to coal and plant costs, before broad commercialization will be economically viable. Some type of government incentives would be needed, and these are under consideration now.

Another obstacle to commercialization of coal liquids technology is current environmental and permitting difficulties which cause long delays in project implementation and create significant risks. A purpose of this meeting is to improve communications on this problem. Environmental concerns cannot be ignored. However, special government legislation may be required for synfuels development to allow demonstration of the technologies on a commercial scale to obtain realistic environmental data. In doing this, a greater public understanding of the need for, and impact of, synthetic fuels must be achieved.

Despite the uncertainties of the future, it is in the national interest to pursue the development of promising synthetic fuels processes through R&D and the pioneer plant stages. Multiple technologies are needed because it is probable that no one process will be best in all circumstances. These developments will provide increased options for the nation, avoid overcommitment to technologies that might prove unattractive, and provide insurance against economic disruption caused by severe limitations in supplies of liquid fuels. Since the United States may have a compelling need for a supplemental source of fuel before the end of the century, these developments should proceed now, as rapidly as possible, but in an orderly manner.

Through the EDS development program, increased understanding of the requirements for successful development of coal liquefaction for a wide variety of coals has been achieved. Programs for the large liquefaction and FLEXICOKING pilot plants have been defined which should provide the data base needed for scale-up to commercial size.

George Huffman, EPA: Would you classify the liquefaction step as a variation of somewhat standardized hydrocracking technology that Exxon has been very much involved in in the past? Can you elaborate a little bit more on the reactor itself?

Mr. Green: Oh, no, I wouldn't classify it as an extension of that technology. The liquefaction reactor is just an empty reactor with a distribution grid at the bottom. The slurry is mixed with the hydrogen and fed into the bottom of the reactor. I don't think there is any secret about what the reactor looks like.

Mr. Huffman: Is it catalytic in the liquefaction?

Mr. Green: No, there is no catalyst in the liquefaction reactor. The catalyst is over in the solvent hydrogenation vessel. It treats only a distillate material.

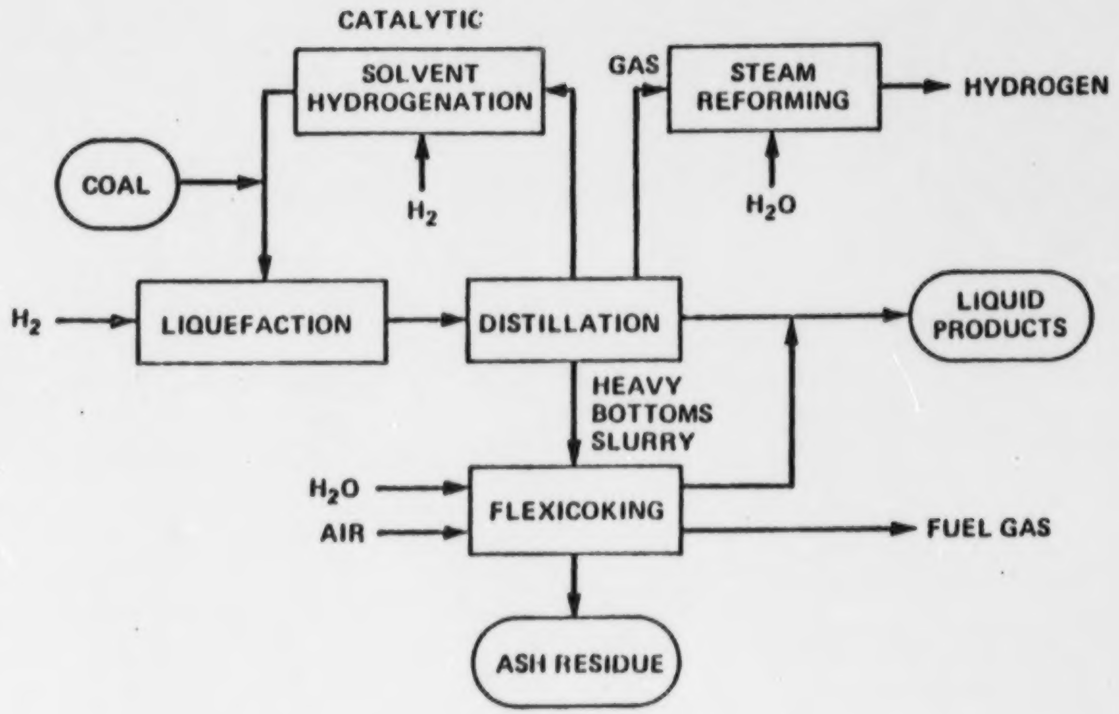
CATALYTIC
SOLVENT HYDROGENATION
H_2
COAL
H_2
LIQUEFACTION
DISTILLATION
GAS
STEAM REFORMING
H_2O
HYDROGEN
LIQUID PRODUCTS
HEAVY BOTTOMS SLURRY
H_2O
AIR
FLEXICOKING
FUEL GAS
ASH RESIDUE

Figure 7. Exxon Donor Solvent Process

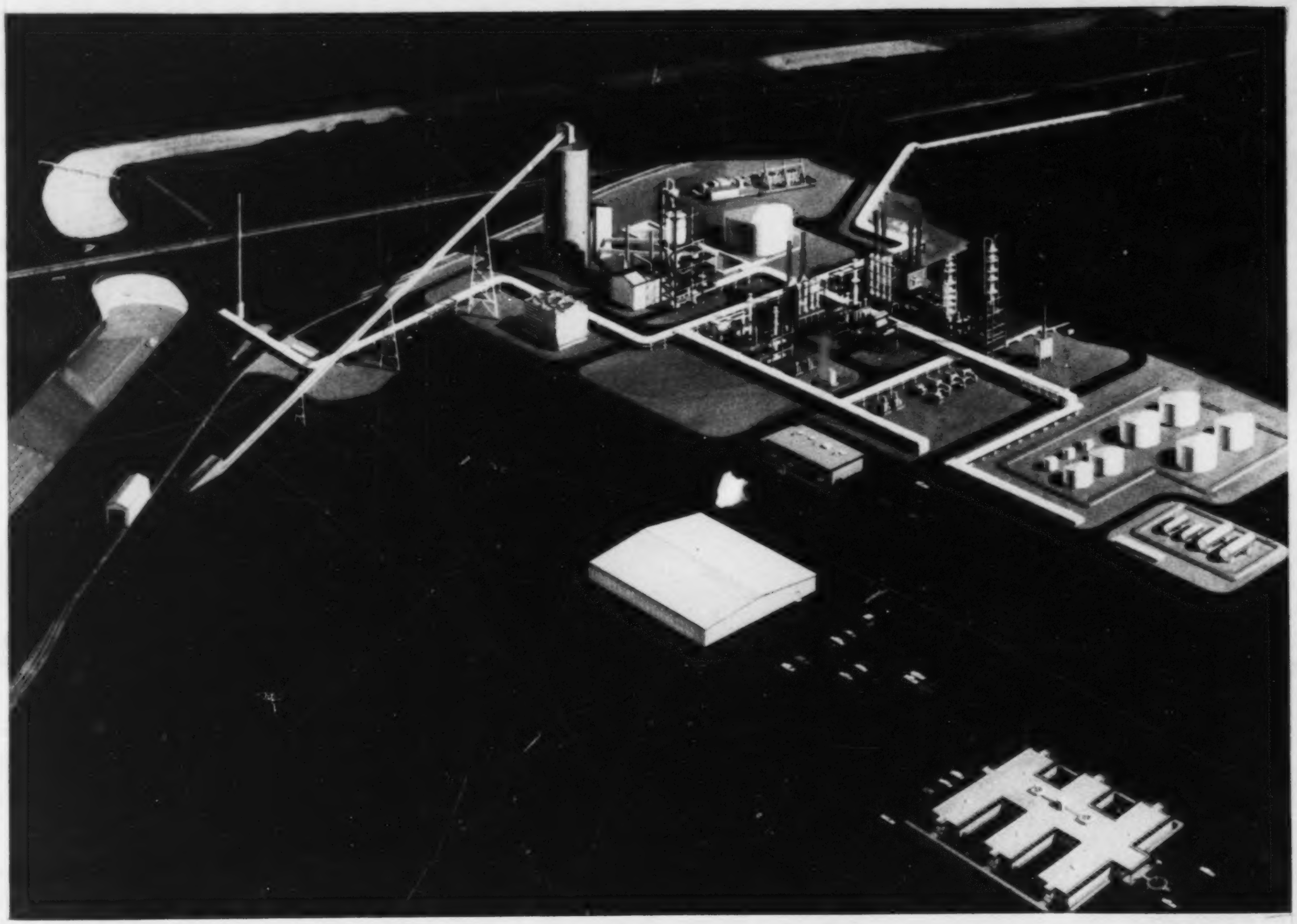

Figure 8. Artist's Conception of 250 Ton-Per-Day Pilot Plant

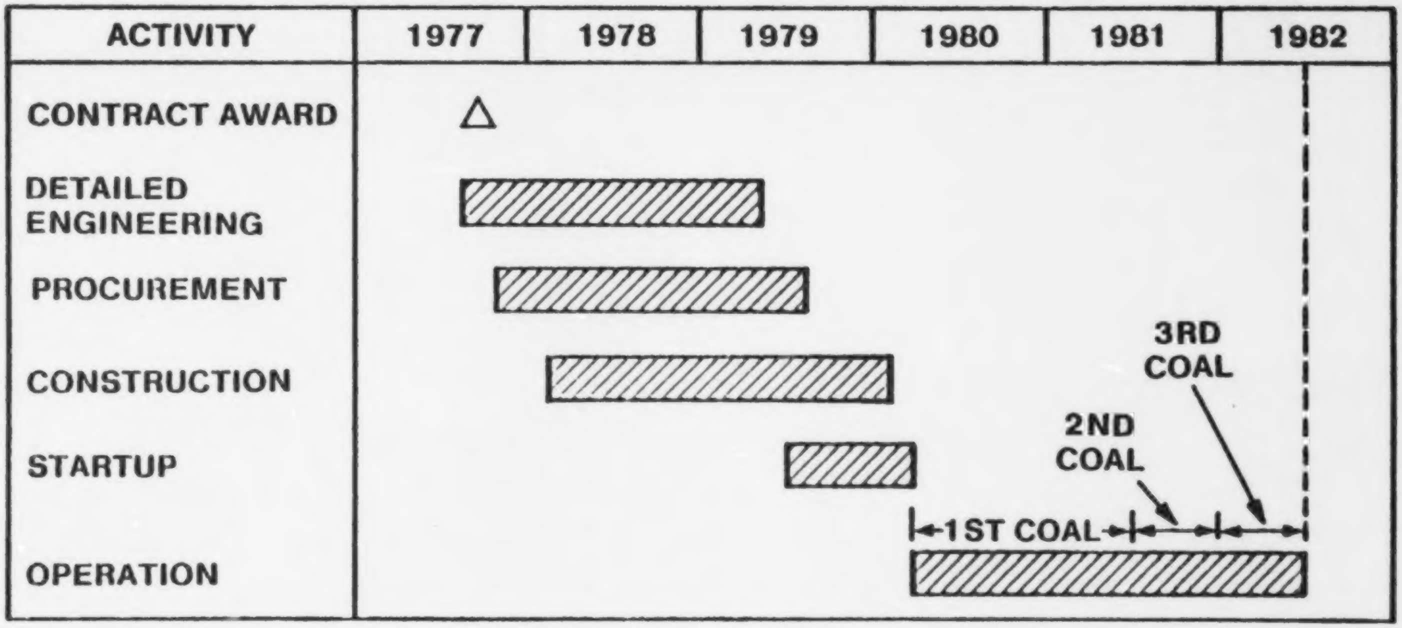

Figure 9. EDS Pilot Plant Schedule

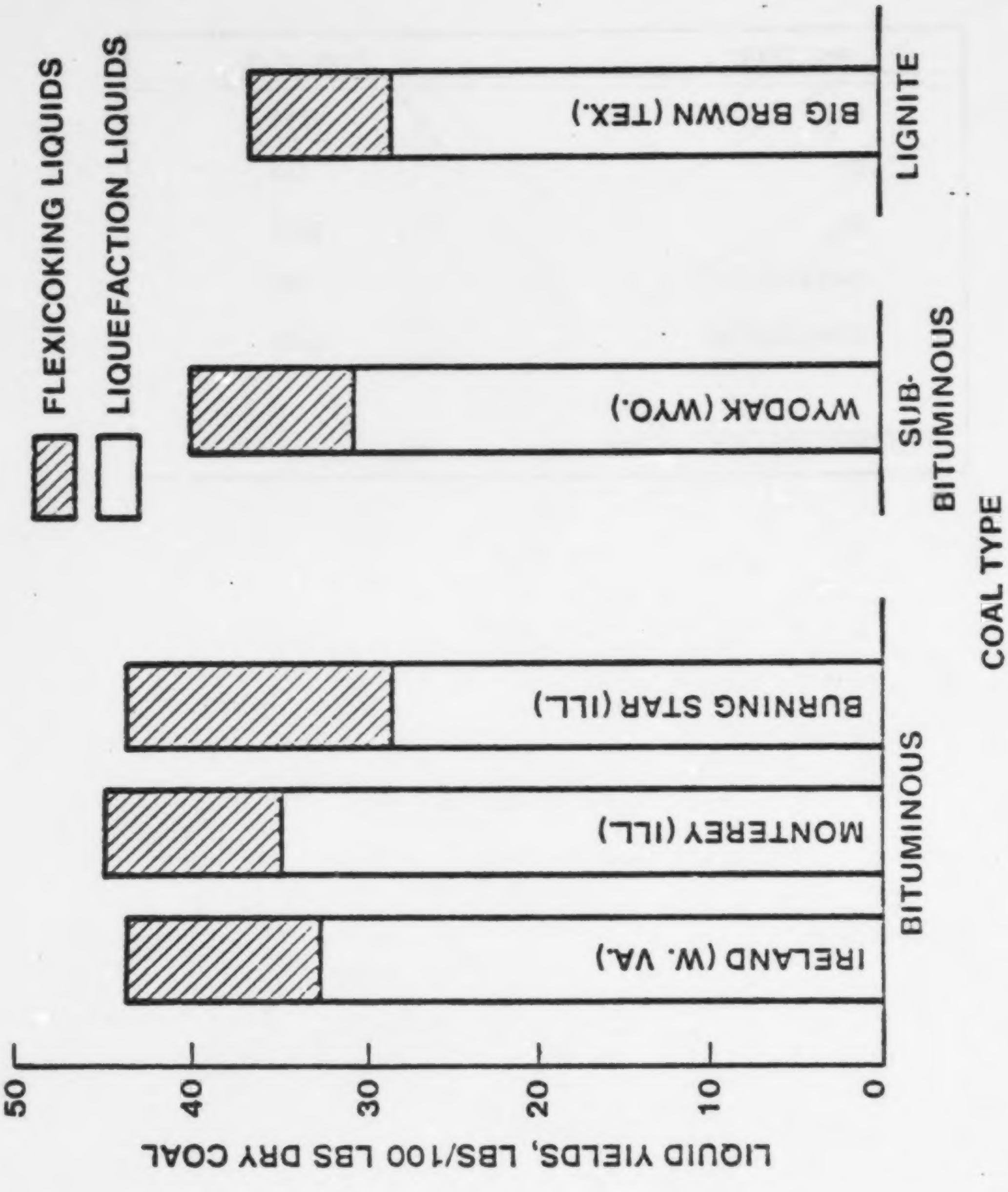

Figure 10. Overall EDS Process Yields

TABLE 14. EXPECTED AIR EMISSIONS, 30 KT/D EDS COMMERCIAL PLANT*

POLLUTANT	TONS/YEAR
SO_2	6150
CO	740
NO_x	3200
PARTICULATES	525
HYDROCARBONS	1575

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*ILLINOIS NO. 6 COAL FEED

TABLE 15. PREDICTED CRITICAL GROUND LEVEL CONCENTRATIONS 30 KT/D EDS COMMERCIAL PLANT* **

($\mu g/m^3$)

	CRITICAL GLC	CURRENT EPA STANDARD
CONTINUOUS EMISSIONS		
SO_2 (24 HR AVE)	35	365
NO_x (1 HR AVE)	100	--
HYDROCARBON (3 HR AVE) 5 MPH WIND AND 800 FT TO BOUNDARY	145	160
PARTICULATE MATTER	10 (1 HR AVE)	75 (ANNUAL AVE)

---

*ILLINOIS NO. 6 COAL FEED

**STACK HEIGHTS
FURNACES - 150 FT
BOILERS - 120 FT
SULFUR RECOVERY - 200 FT

TABLE 16. WASTEWATER CONTAMINANTS AFTER STRIPPING AND PHENOL EXTRACTION, 30 KT/D EDS COMMERCIAL PLANT*

	WPPM
NH_3	80
H_2S	1
CO_2	80
FREE CN^-	NIL
SCN^-	10
CL^-	90
Na^+	500
Ca^{+2}, Mg^{+2} (as $CaCO_3$)	16
$Fe^{+2,+3}$	4
PHENOLICS	50
ORGANIC ACIDS	1500
OIL AND GREASE	30
BOD_5	1410
TOTAL SUSPENDED SOLIDS	30
TOTAL DISSOLVED SOLIDS	2400
RATE, GPM	2500 (MAXIMUM)

---

*AFTER STRIPPING AND PHENOLICS EXTRACTION, BUT BEFORE TREATMENT

TABLE 17. LEACHING OF EDS FLEXICOKING TERTIARY FINES (VALUES IN WPPM)*

LEACHATE, WPPM	ILLINOIS COAL	WYOMING COAL	EPA LIMIT**
F	0.3 (0.9)#	3.3	14-24
NO_3	<3	--	443
Ag	< .002	< .004	0.5
As	< .06	< .1	0.5
Ba	1.8	.2 (6.7)##	10
Cd	.04	< .01	0.1
Cr	.004	< .002 (.03)##	0.5
Hg	.0004	.0006	.02
Pb	[.05]	< .08 (.3)#	0.5
Se	< .04	< .07	0.1

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*USING 12/12/78 EPA TOXICANT EXTRACTION PROCEDURE

**10 TIMES EPA PRIMARY DRINKING WATER STANDARD

#GASIFIER PURGE

##REACTOR CHUNK

TABLE 18. EDS FUEL OIL COMBUSTION TEST RESULTS

- ILLINOIS NO. 6 COAL
- COMBUSTION WITH 10 PERCENT EXCESS AIR

	EDS COAL LIQUIDS		PETROLEUM FUEL OILS	
PARTICULATE EMISSIONS	400 - 1000°F	400°F+	LSFO	RSFO
ASH CONTENT OF SAMPLE, WT%	0.027	0.03	0.02	0.08
TOTAL PARTICULATES WT% ON FUEL	0.03	0.04	0.06	0.17
NO_x EMISSIONS				
NITROGEN, WT% ON SAMPLE	0.55	0.81	0.13	0.44
FLUE GAS CONCENTRATION,* PPM	490	580	300	440

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*CORRECTED TO 3% O_2

Sid Thomson, Fluor, Inc: Did I miss your liquids products? How much hydrocarbon liquids does the 30,000 tons per day make?

Mr. Green: About 55,000 to 60,000 barrels. The 30,000 tons-per-day case that I showed for the particulate emissions yields about 57,000 barrels per calendar day of C-3-plus products.

Mr. Thomson: You say calendar day. Based upon what operating time?

Mr. Green: I think the average is 85 percent.

Dario Monti, DOE: Would you just run through that development schedule of timing one more time?

Mr. Green: Sure. I will have to look at my notes because it changes every day.

Mr. Monti: That's what I figured.

Mr. Green: The problem is that we have to get the data from the large pilot plants. Since the FLEXICOKING program has not been approved, we are at a loss to know what the exact timetable would be, but we said that a design basis could be available in 1982 to support the design of the pioneer plant. Assuming agreement to take the next step, the pioneer plant would then start up in 1988 to 1989, and then the schedule could support the start-up of multiple commercial plants in 1997, if you were to take a year of testing before you started setting the design basis.

Mr. Monti: None of those plants could produce liquids for the present program, as I understand it, during the current schedule of 1985.

Mr. Princiotta: No, I don't think so.

Mr. Green: Well, the first module, the 30,000 barrel-a-day plant, would be available in 1988.

Mr. Monti: Is that the pioneer plant?

Mr. Green: Right. And then that could be expanded as one wanted to get that much more.

Mr. Princiotta: Well, by 1995, what do you think? Is it feasible to have a full-blown plant in operation -- 50,000 to 60,000 barrels?

Mr. Green: Well, we are saying 1997, but it would be presumptuous of me to say that it's impossible to shorten that by two years. But what we are saying is that you go through this pioneer plant stage and then after that the risk of building multiple plants at one time would be what we would consider a normal risk.

Mr. Princiotta: Can you speak for Exxon Corporation as far as their policy toward coal liquefaction? Do they encourage the nation to move in this direction as opposed to other alternatives in the oil business? Is this something the corporation is promoting or is it just another sideline, one of many sidelines of Exxon?

Mr. Green: I can say that we are actively pursuing planning commercial synthetic fuels plants in the area of intermediate-Btu gas from Texas lignite and shale liquids from Colorado oil shales, so those are the projects that we are pursuing on a commercial basis at the study stage. We are not pursuing a commercial EDS plant at the moment, but the technology is not there either in terms of 1980 -- you know, operating our large pilot plant, plus we see the cost of coal liquids to be higher than the other two options I mentioned --

Mr. Princiotta: How high? What are your estimates? I realize they are speculation, too.

Mr. Green: We have just put out a report that shows the results of our study design update. There is a plot in there that shows costs for coal liquids between 47 and 37 dollars per barrel. This is on a 1985 start-up and cost basis.

The difference is how much escalation you want to assume in the price of liquid products over general inflation in the time period when the plants are going to be in operation. The base number we published was something like 3 percent differential escalation -- in other words, 6 percent inflation in the general economy and 9 percent escalation on liquid products. If you take those numbers for the case in which we make some gas by-product -- this is not the case I showed you that had 100 percent FLEXICOKING but a case that has a combination of FLEXICOKING with partial oxidation to make the hydrogen -- about $37 a barrel is the price that you would have to pay in 1985.

Since it escalates at 9 percent a year, by the end of the project the price is pretty high. If you assume no differential escalation, higher required initial selling prices are calculated.

Mr. Princiotta: Do you have any views about direct liquefaction versus indirect? Is Exxon involved in any indirect process? Do you feel that direct liquefaction process will be the technology of the future?

Mr. Green: I guess I have to say that we feel both of them should be pursued and, in fact, in conjunction with our East Texas intermediate-Btu gasification project we are pursuing the gasification step (required for indirect liquefaction).

We have tested coal at SASOL in South Africa, from our East Texas mine or from a deposit there that we have planned to mine, so that we have started the steps that one would need to carry out that piece of it. We have not launched a project on indirect liquefaction.

James O'Hara, Ralph M. Parsons Co.: It's my understanding that the German government has asked two of their companies to begin pre-project work to have three 500,000 barrel-a-day coal liquefaction plants in operation by 1985.

Would you comment on that? I think there obviously are economic incentive factors and there are technical incentives, but I am wondering about the ability to put a plant in operation on that schedule.

Mr. Green: I don't have really any information to offer. Ruhrkohle AG is a participant in our development program, but beyond that I couldn't comment.

Bill Rhodes, EPA: You mentioned a need for large-scale plants to obtain reliable data. Would Exxon's philosophy be to put on best available environmental controls so that reliable data could be obtained from those initial plants?

Mr. Green: That's correct. Our position is that some government regulations will have to be enacted that would allow Best Available Technology to be deemed satisfactory for that plant. What we have in mind is something similar to what was done in the Alaskan pipline where Congress edicted that the environmental laws had been met if Best Available Technology was utilized, and that it was up to the government to monitor the construction to make sure that that is what in fact was put into the plants.

Mr. Princiotta: Do you have any reaction to this pollution control guidance document that we have been talking about in a way that would lay out some control recommendations? Do you have any preliminary reactions to such a document in terms of its positive or negative influence on the industry? Is it being premature or appropriate in the time frame we have been talking about?

Mr. Green: In the case of our process, as I indicated, we think that at the end of the development program we will have developed all the technology that's needed to build that plant on a commercial scale. We have in our program as a program plan the testing of all the environmental control equipment that we think will be necessary.

As I indicated, we do not have a water treating system associated with our large pilot plant. It will just go into the refinery wastewater treating but what we plan to do is to take samples off the large pilot plant and then simulate the treating that we think should be satisfactory and then look analytically at the resulting product. We also have some plans, although this is not on our program yet, to do ecological testing. A lot of these things are dependent on the site -- ecological testing, for example. Since we don't have a site picked for a pioneer plant, we don't have the plan yet.

Dale Denny, EPA: Do you have any plans to do any testing for other than criteria air pollutants?

Lee Byers, Exxon Research: We plan to do some testing for hazardous materials, trace elements, and some toxics.

Mr. Green: I showed you some of the data in abbreviated form, for example, the leachates from the FLEXICOKING wastes. We analyze for many more components than that. I just showed the criteria ones to keep them on the slide.

Mr. Denny: Is that just data for one run or is it several different samples?

Mr. Green: I think it's just one sample that we took from the coking pilot plant. Our plan is that this was a laboratory unit when we run the 70 ton-per-day unit and we would take more samples and do more testing. We didn't feel that we will learn too much more by testing a lot more samples until we get better samples.

John Accardi, EPA: What are the water requirements of the 250 ton-per-day facility?

Mr. Green: I have no idea. Richard Eccles, would you like to offer a comment?

Mr. Eccles: I don't know either.

Yvonne Garbe, EPA: I have several questions on the leachate testing that you did on the solid waste samples. You mentioned you tested using Illinois No. 6 coal and Wyoming coal. Was the Wyoming coal a lignite coal? If not, have you used the tests on any of the processes that you used on the lignite?

Mr. Green: To answer your last question first, no, we have not tested lignite coal. The only two coals that we have run in our FLEXICOKING pilot plants are Illinois No. 6 bituminous coal bottoms, EDS bottoms, and EDS bottoms which were produced from a Wyoming subbituminous coal -- actually, from the Wyodak mine.

Ms. Garbe: Another question, then. Do you project that in your scale of pilot and then commercial there will be any differences in these results? Will the characterization or composition of these wastes change? Do you project any changes?

Mr. Green: I guess as a general rule I would say no, but I know some specific examples. For example, some of our pilot plants are run with much higher steam dilution than we would use commercially, so that the effluents that come out of those are more dilute. We try to take that into account in our engineering studies.

As I mentioned, though, the hydrocarbon emissions are all fugitive so they really don't come from our pilot plant, so to speak, and the sulfur emissions again are from combustion.

You know, there aren't any process gases that go to the atmosphere except the flexicoker gas is cleaned of sulfur and then is burned in the furnaces. So again it is sort of a calculated number of what we think the sulfur level in the fuels will be.

This plant had coal-fired boilers to supply steam so that we had to make an assumption of what the emissions from that would be. So a lot of the sulfur emissions are from the coal-fired boiler, again not really related to the process.

George Huffman, EPA: Did your air emissions chart tabulate emissions after controls were on?

Mr. Green: That's correct.

Kelly Janes, EPA: When you evaluate discharges, what type of criteria do you use to determine the acceptability of the environmental effect?

Mr. Green: For solid wastes we use our understanding of RCRA regulations. We understand the solids are extracted using the EPA toxicant extraction procedure and the standard is a maximum concentration of 10 times the drinking water standard for the criteria pollutants. Criteria for air pollutants are mainly Illinois state regulations plus New Source Performance Standards for coal-fired power plants.

In water most of the criteria are Illinois regulations. I don't think there is any PNA specification yet but as I mentioned, we assumed that one part per billion would be a reasonable number for that at this stage.

Myron Gottlieb, DOE: Back before 1973 the conventional wisdom was that coal liquids would become competitive when petroleum prices increased. Petroleum prices have increased by maybe a factor of five since the early 1970s, and the conventional wisdom still is that coal liquids will become competitive.

What has made the coal liquid estimates increase as quickly as the petroleum increases apparently have made?

Mr. Green: In honesty it is just two things. One, inflation has been a big factor. The cost of building a plant has gone up enormously in the last 10 years.

Mr. Gottlieb: Has it been a factor of five as well?

Mr. Green: No, but it's true that our perception of how much it's going to cost to build one of these commercial plants has increased. I would not blame it on changing emission standards. I think we just probably did not appreciate 10 years ago how complicated it was going to be.

Mr. Gottlieb: Do you think the status of the appreciation now is better than it was?

Mr. Princiotta: Under control?

Mr. Gottlieb: Under control, yes, or should it not?

Mr. Green: It has to be better. In my definition, we are closer to the right answer but I guess I can't respond too well about how close we are.

I do know that we now project our large pilot plant will cost $113 million to complete in February. Our original estimate for it was $110 million and that estimate was made about four years ago.

Mr. Gottlieb: I see. That implies some convergence.

Mr. Green: Right. As I said, that pilot plant only encompasses a portion of the process. It does not have the bottom processing step. It does not have the liquid waste treatment steps, although we think they are pretty conventional steps. It's not really new technology in terms of handling the wastewater. It's a matter of just putting in the right size equipment of the process that we know about.

Robert Hangebrauck, EPA: Getting back to the cost question again on fuels, I saw recently in the IGT newsletter where they were in essence adding or subtracting some credits that related to things like uncertainty in fuel supplies from abroad and certain other credits that they saw fit to include that helped to reduce the cost of the fuel that would be generated in this country.

I was wondering if you folks had maybe done any cross calculations along those lines to see whether or not from a competitive standpoint the $37 to $47 per barrel really looked better than it was when you take into account some of these indirect credits.

Mr. Green: Those are the kinds of credits that we would expect the Congress to take into account in deciding that it was in the national interest to support the technology in some manner.

Mr. Hangebrauck: You have to see them showing up for Exxon.

Mr. Green: Yes. They don't show up in our --

Mr. Princiotta: Profit making.

Mr. Green: You know, from an individual, from our country they are real but --

Mr. Hangebrauck: I don't know if any of them fall into that category or not. They tended to be broad-type credits.

Mr. Green: I don't know that we have evaluated any of them in dollars and cents.

Bruno Loran, Ralph M. Parsons Company: Have the emissions values that you showed been published?

Mr. Green: No. Those have not been published yet. I would anticipate they will be in our next quarterly report, which would be for July through September of 1979. If they are not in there they would be in the next one.

They are not numbers that are confidential or that kind of thing. It's just that we haven't gotten to publishing them. If they are not in there they will be in the documentation for the update of our study design which is being worked on. I don't have a good date for when it will be available, but I would hope that it would be available next year sometime.

Mr. Hangebrauck: Is all of the environmental work that you are doing on the project being done by Exxon? Are you the only party involved?

Mr. Green: That's right.

Mr. Hangebrauck: In testing? Is that right?

Mr. Green: Yes. One slight exception to that would be that we are doing some mouse skin painting work at the moment on some of our product samples and that's being done in a contract laboratory. I can think of other things too, but not in the environmental area. In other areas we have laboratories doing things for us. Pressure-volume-temperature thermodynamic data, for example, is being obtained in Utah.

Mr. Hangebrauck: Do you have any preliminary feelings about products from some of the indirect or direct liquefaction products compared to some of the refinery-type products with respect to the care that may be required in utilization at this point?

Mr. Green: Well, to be truthful, we would have to say that these products will have to be handled very carefully. We have a very elaborate industrial hygiene program in our laboratories. We are planning a substantial industrial hygiene program for our 250 ton-per-day pilot plant. It's the same kind of thing that Gulf is going through at Fort Lewis and I would assume that Ashland will be going through at Catlettsburg.

The materials contain polynuclear aromatics and other materials that are known to be carcinogenic, so you have to be careful with them. They are not white oils, you know, things that are innocuous. We think, though, that it can be controlled. There should not be an unacceptable exposure to the worker, to the surrounding community, or to the user of the products.

We have seen that hydrotreating will reduce the PNA levels, for example. It may be necessary to do some additional product treating beyond the products that I have shown the combustion test results for here because of health reasons. We are working now on a program to submit to DOE for additional health testing. This is one area where we don't have a complete program at the moment.

Mr. Hangebrauck: This will be in essence processing prior to being delivered as feedstock to more conventional refining steps.

Mr. Green: Our present concept is that the naphtha would go to a refinery, the 350°F-, and that the heavier products would be sold directly as products.

The 350 to 650°F might be used as a turbine fuel, for example, so that these would not necessarily go to a refinery and be further processed and then go to the customer. They could go directly to the customer.

Mr. Denny: Have you considered the influence of the Toxic Substances Control Act on marketing those products directly?

Mr. Green: Yes, but probably not fully. As I said, we have mouse skin painting tests underway and we are going to propose additional testing, mutagenic work, teratogenic, a whole battery of tests, to be able to respond to that kind of a request from the government for information.

Mr. Huffman: Regarding the air emissions, you said those were controlled numbers and that the numbers were greater than a hundred tons per year so you couldn't put these plants in a non-attainment area.

Would you speculate that control technology is available to take that extra step if you wanted to go into a non-attainment area, or is it an area where pollution control technologies need to be developed to get that degree of efficiency?

Lee Byers, Exxon: Those numbers are based on the use of Best Available Control Technology in the process. The emission rates that result from employing that technology all meet current New Source Performance Standards in terms of pounds per hour coming out of the stack.

So, therefore, if you were in an attainment area, and the plant did not impact on a Class 1 area, we would be permitted to build a plant because the emission rates are in compliance with at least existing standards.

Mr. Green: Now I know why we were asked to talk last.

Mr. Denny: In your hydrocarbon emissions you said they were all fugitive, is that correct? Did you include some sort of a maintenance program for control of those emissions?

Mr. Byers: The hydrocarbon emissions were based on emission factors that we have developed for petroleum-type fugitive emissions and are based upon the kinds of maintenance and operating programs or procedures that we follow now.

I know that EPA is working on the studies that indicate that fugitive emissions can be controlled significantly just by improving maintenance and operating procedures, and so I have not factored those kinds of improvements into these emission numbers.

Mr. Green: You could probably show the need for research in those kinds of areas, too --better pumps, seals, or at least how to design better ones to last longer.

John Farmer, EPA: You indicated in your response about the amount of emissions that your estimates were based on the use of Best Available Control Technology and that it was based on meeting the New Source Performance Standards.

Mr. Green: Yes.

Mr. Farmer: I was wondering what New Source Performance Standards you meant, because we don't have any New Source Performance Standards.

Mr. Byers: Well, as Bob mentioned, for example, coal-fired utility boilers.

Mr. Green: Yes, they were based on .03 pounds per million Btu particulates, half a pound per million Btu.

Mr. Byers: .6 pounds per million for SO_2.

Mr. Green: Okay. And the NO_x was .5 pounds per million Btu, I believe.

Mr. Farmer: That's only for burning the fuel. What about the process emissions, the actual process of liquefaction?

Mr. Byers: You see, a large part of those emissons of SO_2 and particulates comes from burning fossil fuels for generating steam.

Mr. Green: The process streams don't really go to the atmosphere. The emissions come from the process furnaces because we gasify the bottoms from the liquefaction process, scrub that gas to take the hydrogen sulfide out and then that's the fuel for the process, so the emissions are from the process furnaces. Another big source of the emissions are the coal-fired utility boilers that generate the steam for the process. That was the big sulfur emitter and the particulate emitter was the coal-fired steam boiler.

The second day's session was opened by Mr. Frank Princiotta, Director of EPA's Energy Processes Division, at 9:00 a.m., October 24, 1979.

He introduced the first speaker of the day, James B. O'Hara of the Ralph M. Parsons Company.

Ralph M. Parsons Plans in the Area of Coal Liquefaction: James B. O'Hara, Ralph M. Parsons Company

The Ralph M. Parsons Company, as an engineering-construction firm, is a service company as contrasted with an operating company.

Our coal liquefaction plans, therefore, are based on our capacity to respond to industry needs to design, engineer, procure, and construct various types of coal liquefaction facilities wherever needed. We currently do not plan to offer a proprietary liquefaction process; instead we offer familiarity with the major technologies and the management, engineering, procurement, and construction skills to service any of these technologies. We anticipate that our level of activity in the field will depend on the number and types of coal liquefaction plants to be built.

We are watching and participating not only in the proceedings in Washington that will lead to final formulation of synfuels program legislation, but also in private sector discussions. The national program should, in our judgment, maximize the freedom and incentives for private industry to build and operate coal liquefaction plants.

We would categorize our planned areas of performance as follows: managing contractor, sulfur systems engineering, process plants, coal supply, and utilities. I will comment to a greater or lesser extent on each of these areas.

We anticipate that the synfuels plants will be large and complex. A number of them may be built in isolated areas to maximize access to coal and minimize the environmental impact. The success of these coal liquefaction projects will depend on large-project experience to assure meeting schedules, performance standards, and budgets while erecting the facilities in a responsible and environmentally acceptable fashion.

The ability to meet schedules becomes particularly important for these projects because of the large investments involved; a project stretch-out results in idling both large blocks of capital dollars and large numbers of personnel. We can put dollar values on that; you are aware of the estimated fixed capital investment of these plants and the cost of money these days. A little arithmetic in terms of a one-year stretch-out of a multibillion-dollar facility, with staffing which may be on the order of 2,000 people, will quickly tell you the incentive for careful scheduling.

A contractor's prior large-project experience will be a major factor in the success of the synfuels commercializaton program. Our experience in large projects, including the billion-dollar-plus variety, includes serving as managing contractor for the Prudhoe Bay gas separation-conditioning-injection system plus support facilities in Alaska, which is an antagonistic climate; the Jeddah and Yanbu superprojects in Saudi Arabia; three grass-roots refineries built in the 1970s for ARCO at Cherry Point, Washington; the Marathon Oil refinery at Garyville, Louisiana; the Dow Chemical refinery at Freeport, Texas; and large mining operations including the Sar Chesmeh mine in Iran and the La Caridad mine in Mexico.

One of the objectives of the U.S. coal liquefaction program will certainly be to produce environmentally acceptable fuels. Because of the sulfur content of U.S. coals, the sulfur management system, we feel, will be an integral part of any design.

The effective design and operation of facilities will involve removal and recovery of the sulfur content of feed coal in coal liquefaction plants, production of environmentally acceptable synfuels, and operation of the plant in an environmentally acceptable fashion.

From our experience, each plant will have its own criteria for sulfur system performance. We have designed approximately 80 percent of the free world's sulfur recovery plant capacity. This amounts to approximately 50,000 long tons per day of recovered sulfur. We plan to make this broad capability and experience in sulfur systems engineering-construction available to the synfuels program.

There are a number of process technologies that have been used in sulfur system design/operation, including techniques to handle the apparently difficult sulfur recovery problems that will be encountered in coal liquefaction plants. To illustrate, a typical coal conversion plant produces an acid gas with three characteristics which differentiate it from that produced in a typical petrochemical unit. The first is high volume flow rate; the second, low hydrogen sulfide concentration; and the third, contaminants that are detrimental to effective and reliable sulfur recovery. For instance, a typical petrochemical unit may produce an acid gas stream that contains 60 to 90 percent hydrogen sulfide, while a coal conversion plant can produce streams with 10 percent or less hydrogen sulfide.

In recent years, the Claus unit, the workhorse of sulfur recovery, has been used extensively with streams containing 20 to 30 percent hydrogen sulfide or even less. We have recently built modified sulfur-burning Claus units to handle a stream containing 7 to 8 percent hydrogen sulfide. This relatively new process procedure has been used in a Canadian plant. It produces 400 long tons per day of sulfur from a feed stream containing 7 to 8 percent hydrogen sulfide.

For feed streams containing less than 7 percent hydrogen sulfide, a Claus unit is too large physically and becomes uneconomical. While we are not in a position to talk in too much detail, we are developing an entirely new process to handle feeds as low as 1 percent hydrogen sulfide.

At present, for streams containing less than 5 percent hydrogen sulfide, we would normally recommend use of the Stretford process. This is a hydrogen sulfide absorption procedure that is well known and respected throughout the industry.

We also offer a proprietary tail gas process called the BSRP. We would typically combine a pre-hydrogenation step (to convert the sulfur constituents to hydrogen sulfide) with the Stretford process. There are two vintages of these tail gas processes that would be included.

The coal gasifier product normally will contain about 95 percent of the sulfur as hydrogen sulfide; the remaining 5 percent exists as carbonyl sulfide. In general, this is costly to remove. In another look at the future, we are developing a low-cost method of carbonyl sulfide removal. The results so far are promising.

We have done design work on what we understand would be the world's largest Stretford unit. This would have served as part of a commercial coal gasification plant. We have worked on the design of even larger units for use in the oil shale industry.

In any coal liquefaction plant, we would suggest that the system first be analyzed and that the elements of the sulfur-recovery system be selected essentially on a tailor-made basis. We are designing the sulfur systems for both the SRC-I Coal Liquefaction Demonstration Plant scheduled to be constructed at Newman, Kentucky, and the Illinois Coal Gasification Group Pipeline Gas Plant, which is in the final stages of competition for potential construction in Perry County, Illinois.

In addition to the sulfur system in the SRC-I plant, we are also designing a gas processing plant. In the Illinois plant, we are designing the methanation section. These tend to fit together. The methanation, incidentally, is a proprietary Parsons technology.

Parsons has developed conceptual designs for each of the generic types of coal liquefaction plants. This includes direct liquefaction (including solvent extraction and donor solvent), indirect liquefaction, and pyrolysis. For orientation, Figure 11 shows an artist's conceptual drawing of a pyrolysis-based liquefaction complex, while Figure 12 shows a solvent extraction-based liquefaction plant. In general terms, the complexes shown would process 25,000 to 35,000 tons per day of feed coal and occupy about a square mile. The plants contain many multiple process and supporting units, as illustrated by Table 19. These consist of coal receipt and handling, coal liquefaction, coal gasification (for hydrogen and fuel gas production), product recovery, product refining and upgrading, gas plants, sulfur plants, and effluent treatments, among others. Each complex will be the equivalent of a small industrial city, serve a plant population measured in the thousands, and handle large tonnages of incoming and outgoing materials.

The nature and expected treatment procedures for effluents from the coal liquefaction plant will illustrate the environmental characteristics of coal liquefaction plants and the nature of facilities that might be typical of future large coal liquefaction plants. The plant chosen for this illustration is a hydroliquefaction plant which has been illustrated by the artist's conceptual drawing shown in Figure 12. A simplified block flow diagram for this facility is shown in Figure 13. Here we see the coal preparation, the coal dissolving, the product separation, product recovery and refining, gas plant, sulfur plant, hydrogen production for use in the coal dissolving and product hydrotreating steps, and power/steam generation. Fuel for utilities in this case is produced by gasification of coal followed by particulate and sulfur removal from the raw gas. For those cases where the costs of conceptual coal liquefaction environmental facilities have been estimated, they have been in the same percentage range as is encountered for grass-roots oil refineries, i.e., 10 to 15 percent of the total facility investment.

The product distribution and overall material balance for the example plant is shown in Figure 14. The products consist of approximately 75,000 barrels a day of liquid fuels plus 165 million standard cubic feet per day of SNG.

Figure 15 schematically depicts sources of gaseous contaminants, projected treatment procedures, and quantities and compositions of gaseous effluents to the atmosphere. Here the major air pollution abatement effort is directed to desulfurizing the gases which are generated during the coal liquefaction and gasification steps. The objective is to produce environmentally acceptable fuels. The desulfurization process would include gaseous fuels produced for in-plant consumption, making the overall plant operation geared to meet practical regulatory limits.

Very briefly -- in this case a process gasifier would be used to react process-generated char plus feed coal with steam and oxygen to produce hydrogen, carbon monoxide, carbon dioxide, methane, hydrogen sulfide and lesser amounts of ammonia, carbon oxysulfide, cyanides and sulfur dioxide. The gasifier used in this case was an entrained type; the particulates in the gasifier effluent would be separated by combined use of cyclone and other solid-gas separators, the gas then shift-converted to increase the hydrogen concentration, and processed in a selective acid gas removal unit. Products from acid gas removal would consist of a hydrogen sulfide enriched stream which would be processed in a Claus sulfur plant to produce elemental sulfur; effluent from the Claus plant would then pass through a tail gas unit before venting to the atmosphere. A carbon dioxide rich stream, also produced in the acid gas removal unit, would be vented while the prime process gas stream containing product hydrogen, carbon monoxide, and lesser amounts of methane and other constituents would be fed to the coal liquefaction section.

The gaseous products from the coal liquefaction reactor (dissolver) would also be subjected to acid gas treatment, with the hydrogen sulfide removed at this point also going to the sulfur plant. The product from this acid gas treatment can be separated by cryogenic means into low-sulfur products consisting of SNG, LPGs, and naphtha.

In this particular design the utilities were generated from fuel gas; a separate gasifier is installed for this purpose which would also have a sulfur removal unit, in this case a Stretford plant. This fuel gas is used for steam generation and process heaters with the combustion gases being vented.

Current projections are that about 95 percent of the sulfur in a high-sulfur feed coal can be recovered as elemental sulfur. This is illustrated in Table 20.

Expected sources of contaminated aqueous streams, their treatment and expected disposition are illustrated in Figure 16. Here the degree of contamination of the wastewater streams is greatest for those listed at the top of the page and decreases progressively in moving to the bottom of the page.

The wastewater treatment is a combination of recycling and discharge of aqueous effluents. The most heavily contaminated streams will be steam distilled, with organic contaminants separated and then fed to the process gasifier for thermal destruction. Those streams with moderate contamination are purified physically and biologically and can be used for slag quenching or ash quenching, depending on the type of gasification process used. Preferably the water system will be completely "bottled," with total recycle of liquids. An alternative is to treat the lightly contaminated streams to an environmentally acceptable level followed by discharge to the river.

The delivery, storage, reclaiming, and preparation of the large quantities of coal will require significant facilities and capital investments. The design must be responsive to the need to operate in an environmentally acceptable manner.

Each commercial coal liquefaction complex will require production of large quantities of steam and electricity. To illustrate, a 100,000 barrel-per-day-equivalent complex, operating with a thermal efficiency in the range of 70 to 75 percent, can require on the order of 6 million pounds per hour of steam and 200 megawatts of electrical power. The utility units will be integrated with the process units wherever practical.

In summary, Parsons is closely following developments in the synfuels program as it is evolving in Washington as well as in the private sector. Our plans are to supply design, engineering, procurement, and construction services for coal liquefaction plants in such a way that the plants will perform in an environmentally responsible manner.

John Accardi, EPA: Do you have any figures on how much water a 35,000 ton-per-day coal facility uses?

Mr. O'Hara: I think we are drawing 17,500 gallons a minute from the river, but we are returning about 3,000 gallons a minute. So that would be a net draw of about 14,000.

I would merely mention here that there are some incentives to go to a completely bottled plant. That is an important point as far as environmental effects are concerned. The facility is a net large chemical consumer of water and that is an important point.

The way you can use that is to use your gasifier, particularly a high-temperature gasifier as an incinerator. In other words, you can take the waste aqueous streams, clean them to a certain degree, and then feed them to the gasifier. Alternatively, you have an option to further clean them prior to disposal.

Mr. Accardi: You said 12 percent is allocated for environmental control equipment or capital costs. Do you have any percentage on operating cost as a result of the environmental control equipment?

Mr. O'Hara: Not that I can recall.

Bob Hangebrauck, EPA: One of your slides showed unit designed areas that you had some cost for, but I don't think there was one on there for solid waste. Was that just carried somewhere else or costed out on another kind of design basis?

Mr. O'Hara: We did have a solid waste disposal. I think we carried most of that in the operating costs.

Bruno, you may want to comment on that.

Bruno Loran, Ralph M. Parsons Co.: Solid waste not treated is 100 percent homogeneous. There are solid wastes, such as residue from coal cleaning and so on, that go back to the

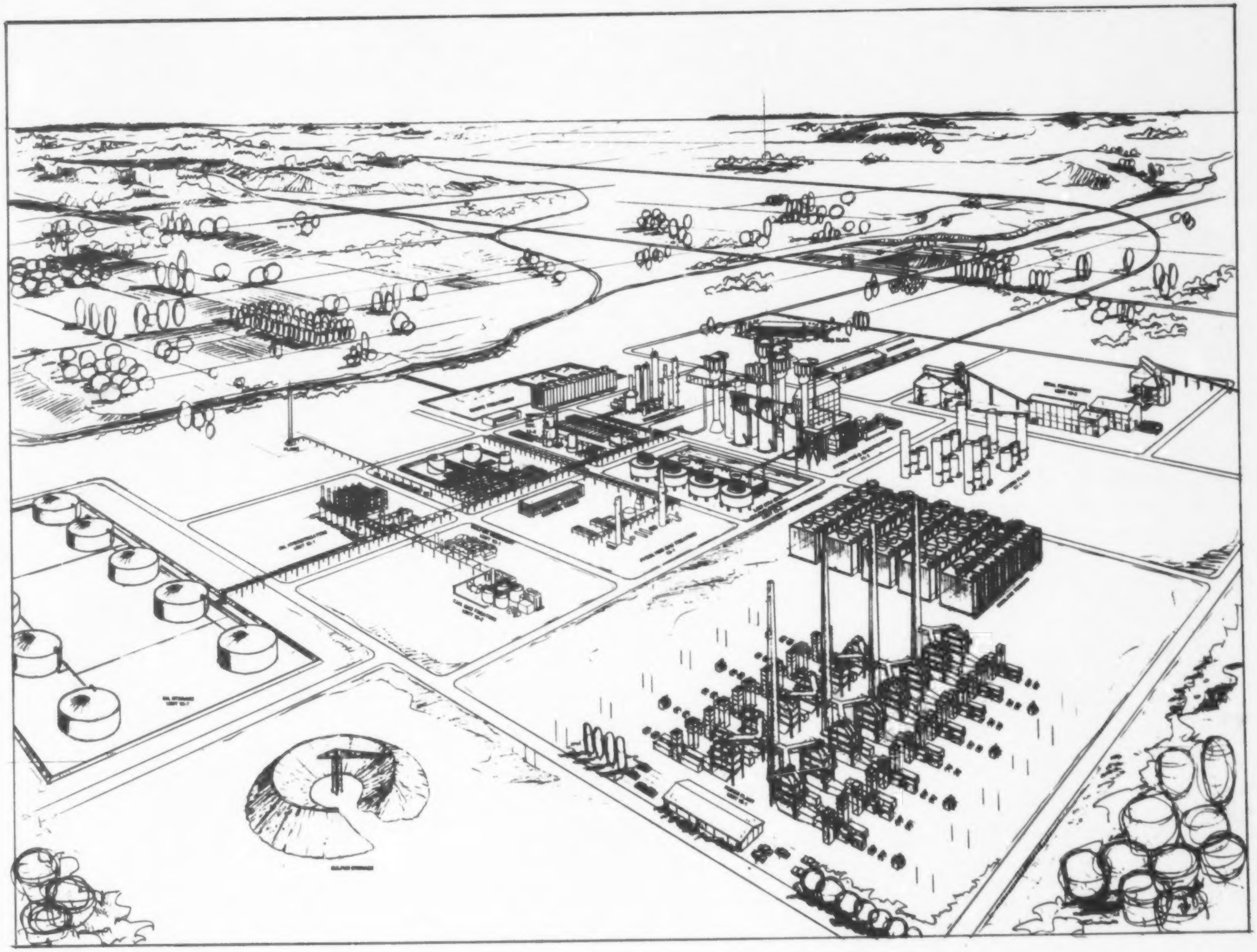


Figure 11. Artist's Concept of Combined Clean Fuel/
Power Facility, COED Process

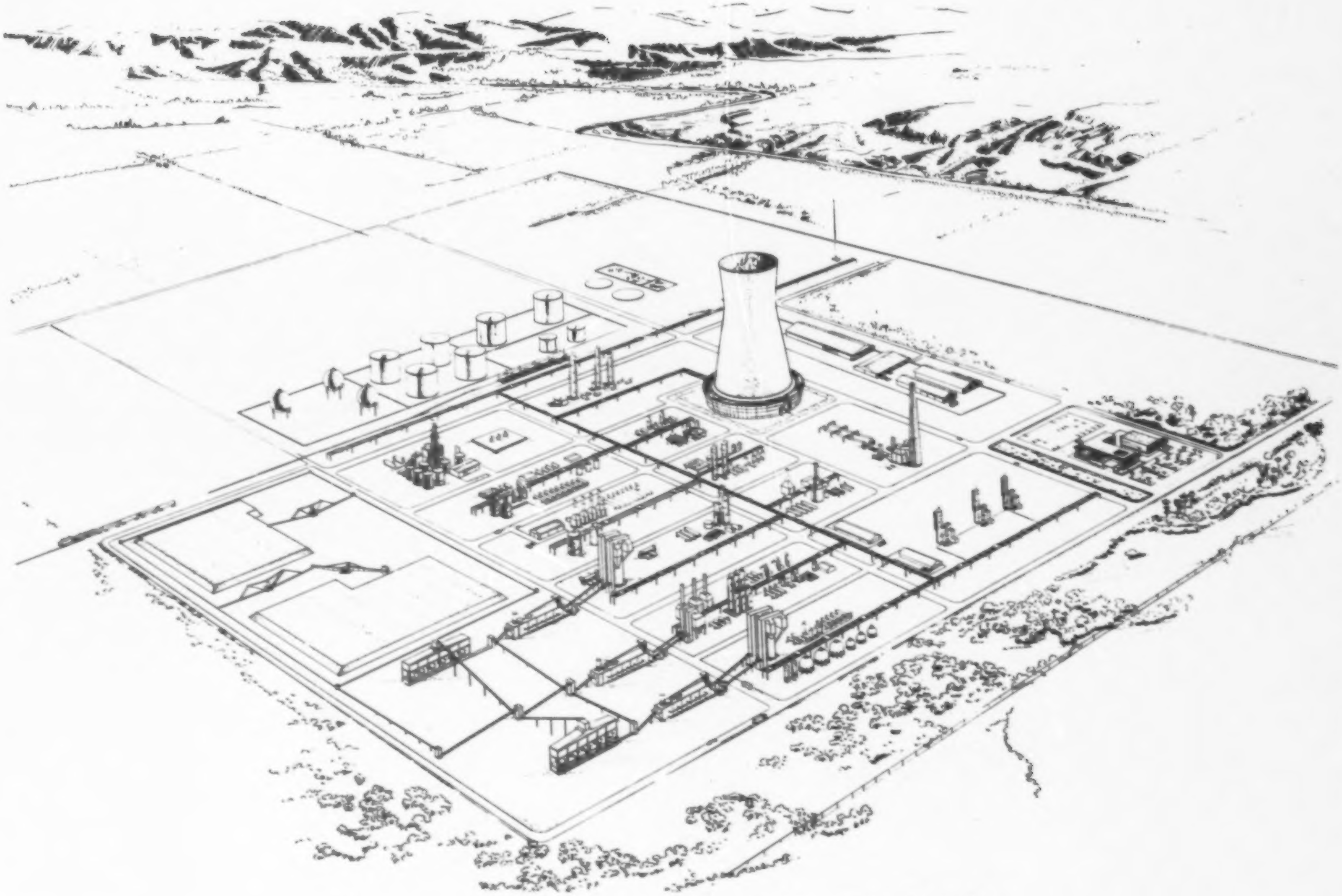


Figure 12. Artist's Concept, Solvent Extraction-Based Liquefaction Plant

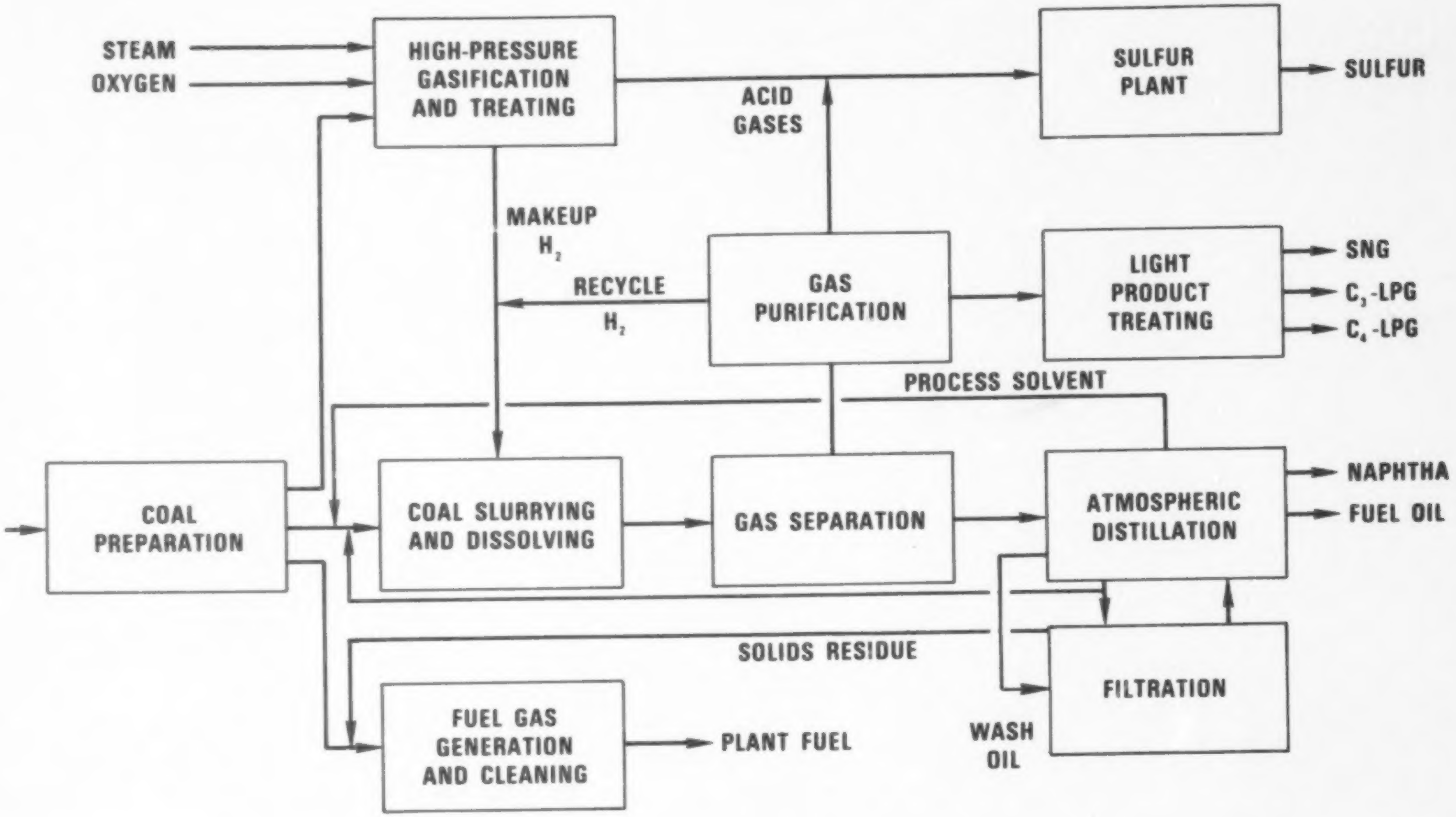

STEAM
OXYGEN
HIGH-PRESSURE GASIFICATION AND TREATING
ACID GASES
SULFUR PLANT
SULFUR
MAKEUP H_2
RECYCLE H_2
GAS PURIFICATION
LIGHT PRODUCT TREATING
SNG
C_3-LPG
C_4-LPG
PROCESS SOLVENT
COAL PREPARATION
COAL SLURRYING AND DISSOLVING
GAS SEPARATION
ATMOSPHERIC DISTILLATION
NAPHTHA
FUEL OIL
SOLIDS RESIDUE
FILTRATION
FUEL GAS GENERATION AND CLEANING
PLANT FUEL
WASH OIL

Figure 13. Simplified Block Flow Diagram: Conceptual Design, Commercial Oil/Gas Plant

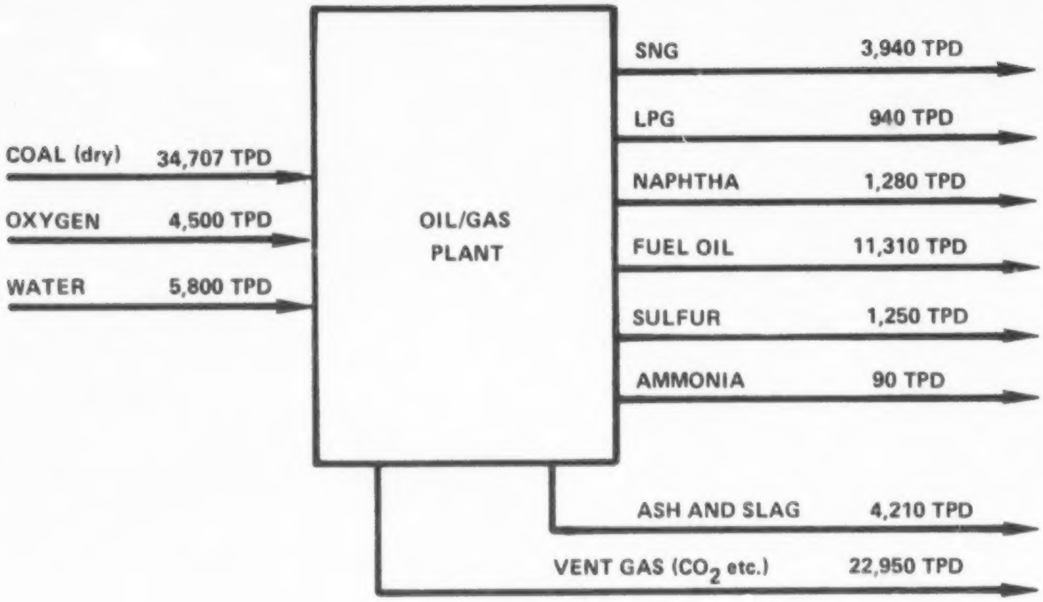

COAL (dry) 34,707 TPD
OXYGEN 4,500 TPD
WATER 5,800 TPD
OIL/GAS PLANT
SNG 3,940 TPD
LPG 940 TPD
NAPHTHA 1,280 TPD
FUEL OIL 11,310 TPD
SULFUR 1,250 TPD
AMMONIA 90 TPD
ASH AND SLAG 4,210 TPD
VENT GAS (CO_2 etc.) 22,950 TPD

Figure 14. Typical Overall Material Balance
(TPD = Tons Per Day)

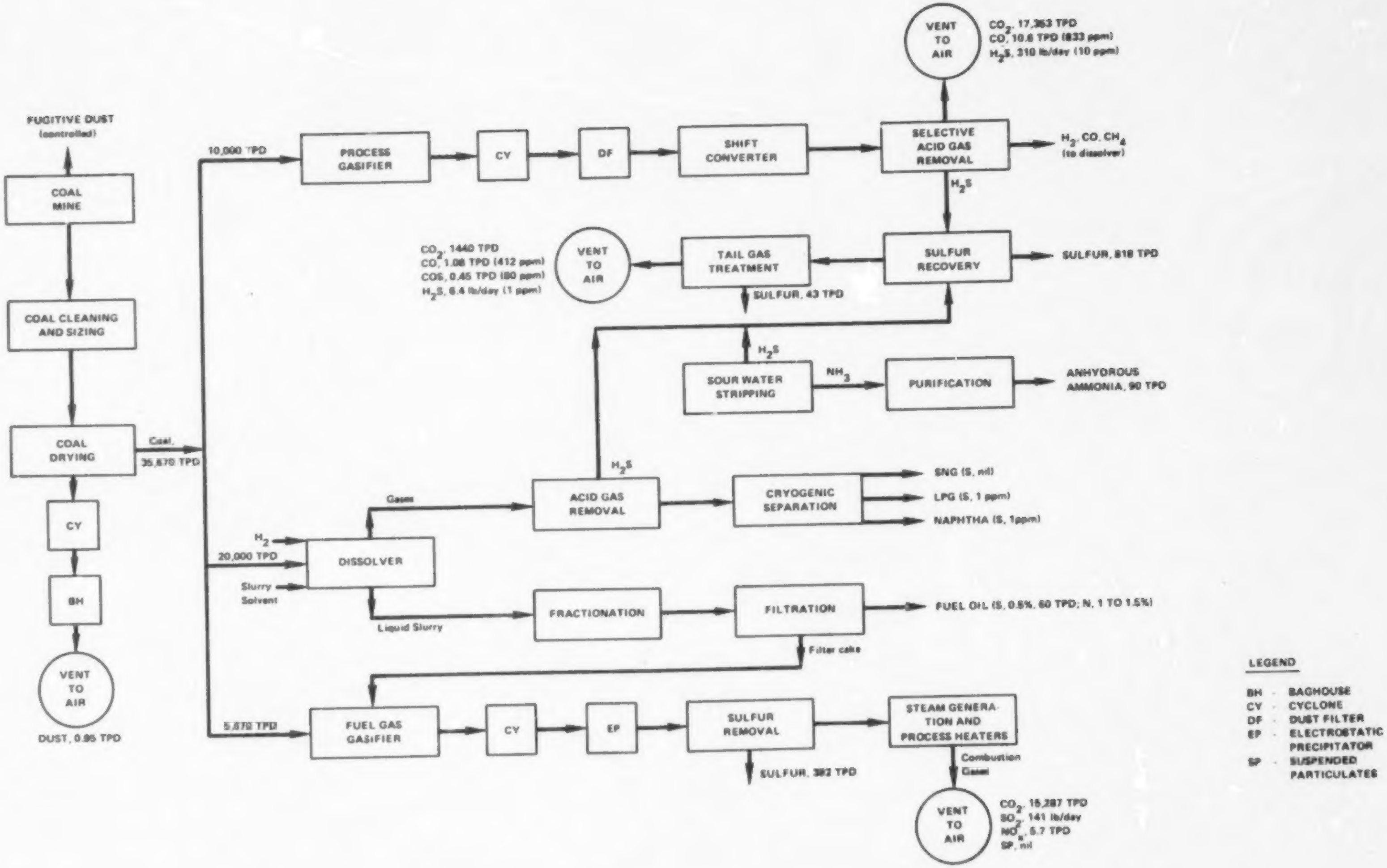

FUGITIVE DUST (controlled)
COAL MINE
COAL CLEANING AND SIZING
COAL DRYING
Coal, 35,670 TPD
CY
BH
VENT TO AIR
DUST, 0.95 TPD
10,000 TPD
PROCESS GASIFIER
CY
DF
SHIFT CONVERTER
SELECTIVE ACID GAS REMOVAL
VENT TO AIR
CO_2, 17,363 TPD
CO, 10.6 TPD (833 ppm)
H_2S, 310 lb/day (10 ppm)
H_2, CO, CH_4 (to dissolver)
H_2S
SULFUR RECOVERY
SULFUR, 818 TPD
TAIL GAS TREATMENT
VENT TO AIR
CO_2, 1440 TPD
CO, 1.08 TPD (412 ppm)
COS, 0.45 TPD (80 ppm)
H_2S, 6.4 lb/day (1 ppm)
SULFUR, 43 TPD
H_2S
SOUR WATER STRIPPING
NH_3
PURIFICATION
ANHYDROUS AMMONIA, 90 TPD
H_2
20,000 TPD
Slurry Solvent
DISSOLVER
Gases
H_2S
ACID GAS REMOVAL
CRYOGENIC SEPARATION
SNG (S, nil)
LPG (S, 1 ppm)
NAPHTHA (S, 1ppm)
Liquid Slurry
FRACTIONATION
FILTRATION
FUEL OIL (S, 0.5%, 60 TPD; N, 1 TO 1.5%)
Filter cake
5,670 TPD
FUEL GAS GASIFIER
CY
EP
SULFUR REMOVAL
SULFUR, 392 TPD
STEAM GENERATION AND PROCESS HEATERS
Combustion Gases
VENT TO AIR
CO_2, 15,287 TPD
SO_2, 141 lb/day
NO_x, 5.7 TPD
SP, nil
LEGEND
BH - BAGHOUSE
CY - CYCLONE
DF - DUST FILTER
EP - ELECTROSTATIC PRECIPITATOR
SP - SUSPENDED PARTICULATES

Figure 15. Block Flow Diagram: Air Pollution Abatement, Oil/Gas Plant

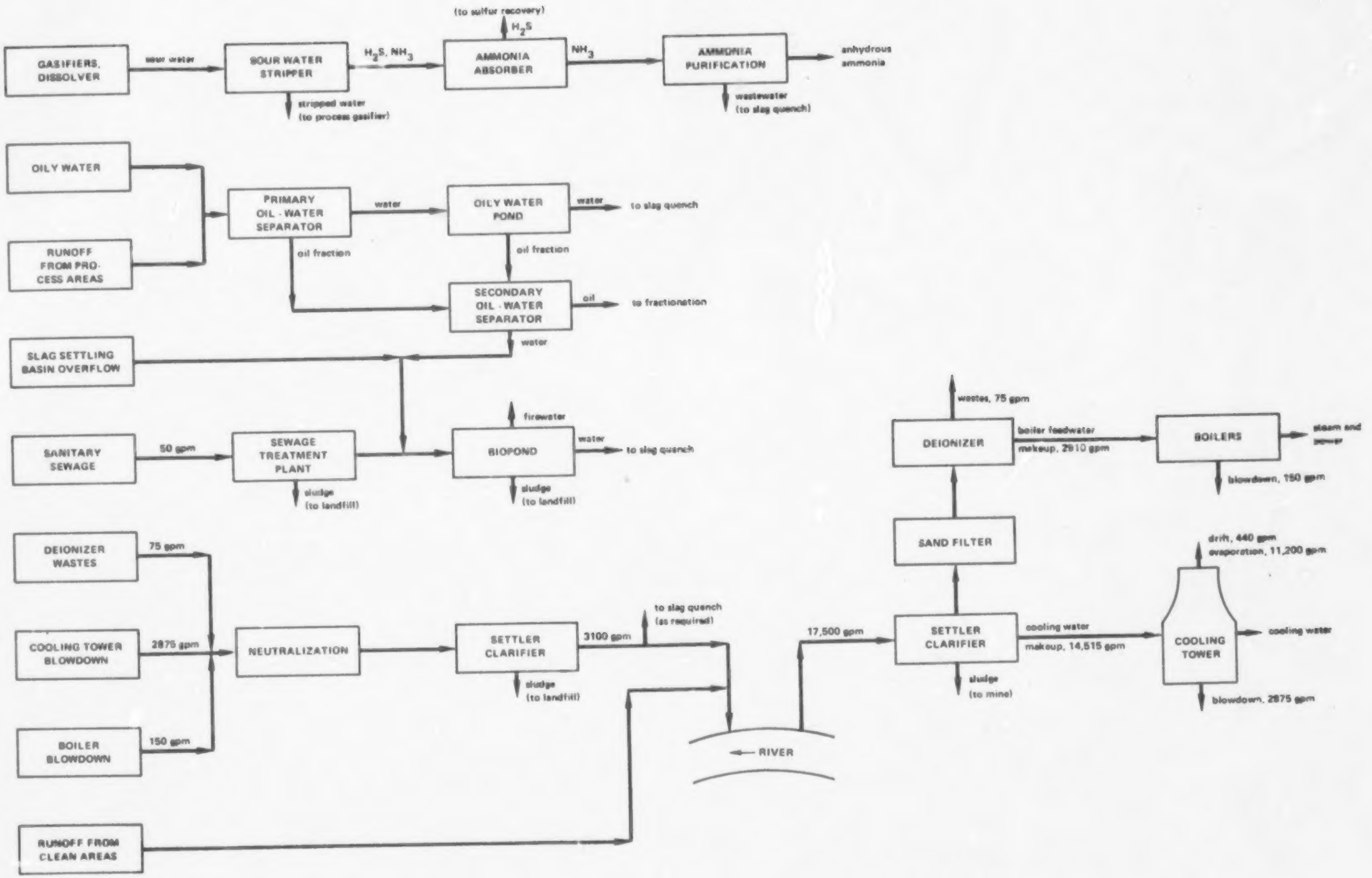

GASIFIERS, DISSOLVER
sour water
SOUR WATER STRIPPER
stripped water (to process gasifier)
H_2S, NH_3
(to sulfur recovery)
H_2S
AMMONIA ABSORBER
NH_3
AMMONIA PURIFICATION
wastewater (to slag quench)
anhydrous ammonia
OILY WATER
RUNOFF FROM PROCESS AREAS
PRIMARY OIL - WATER SEPARATOR
water
oil fraction
OILY WATER POND
water
to slag quench
oil fraction
SECONDARY OIL - WATER SEPARATOR
oil
to fractionation
water
SLAG SETTLING BASIN OVERFLOW
SANITARY SEWAGE
50 gpm
SEWAGE TREATMENT PLANT
sludge (to landfill)
firewater
BIOPOND
water
to slag quench
sludge (to landfill)
DEIONIZER WASTES
75 gpm
COOLING TOWER BLOWDOWN
2875 gpm
BOILER BLOWDOWN
150 gpm
NEUTRALIZATION
SETTLER CLARIFIER
sludge (to landfill)
3100 gpm
to slag quench (as required)
RUNOFF FROM CLEAN AREAS
RIVER
17,500 gpm
SETTLER CLARIFIER
sludge (to mine)
SAND FILTER
DEIONIZER
wastes, 75 gpm
boiler feedwater makeup, 2910 gpm
BOILERS
steam and power
blowdown, 150 gpm
cooling water makeup, 14,515 gpm
COOLING TOWER
drift, 440 gpm
evaporation, 11,200 gpm
cooling water
blowdown, 2875 gpm

Figure 16. Block Flow Diagram: Water Treatment and Supply, Oil/Gas Plant

TABLE 19. ILLUSTRATIVE LIST OF PLANT UNITS: COAL LIQUEFACTION COMPLEX

Unit No.	Description
08	Coal Mine
09	Coal Preparation
10	Coal Storage, Grinding, and Drying
11	Oxygen Plant
12	SRC Dissolving
13	SRC Atmospheric Distillation
14	SRC Vacuum Distillation
15	Pyrolysis
16	Pyrolysis Atmospheric Distillation
17	Sour Gas Compression
18	Process Gasification
19	Shift Conversion
20	Selective Acid Gas Removal
21	Heavy Liquids Hydrotreating
23	Coking
24	Naphtha Hydrotreating
25	Naphtha Reforming
26	Olefinic Gas/Acid Gas Removal
27	Saturate Gas/Acid Gas Removal
28	Olefin Recovery and Polymerization
29	Hydrogen Recovery and Purification
30	SNG Purification
31	LPG Fractionation
32	Sulfur Plant
33	Fuel Gas Generation
34	Fuel Gas/Acid Gas Removal
35	Steam and Power Generation
36	Process Wastewater Treating
37	Shops and Buildings
38	Fire Water System
39	Potable and Sanitary Water System
40	Raw Water System
41	Effluent Water Treating
42	Product Storage
43	Flare System
44	Site Preparation, Roads, and Railroads
45	Instrument and Plant Air Systems

TABLE 20. SULFUR BALANCE (TPD)

Total Input From the Typical Feed Coal		1312.7
Outputs:	As Elemental Sulfur	1252.3
	In the Fuel Oil	59.9
	As Carbon Oxysulfide Emissions	0.2
	Adsorbed on Catalyst Beds	0.3
		1312.7

mine. There are also other solid wastes, such as sludges from treatment systems, that may have objectionable components. They all get the same treatment. That cost includes returning the bulk to the mine.

Mr. Hangebrauck: Where is that carried in your cost?

Dr. Loran: That includes all of these.

Mr. Princiotta: It's distributed over several cost items?

Dr. Loran: Right.

Mr. Princiotta: You have a broad perspective on coal liquefaction. Could you give us your personal views on the potential of indirect versus direct liquefaction? Which technologies do you see coming on earlier? What do you think the ultimate will be? Do you think 20 years from now we will just see direct liquefaction?

Mr. O'Hara: That's a very broad question.

We have stated publicly since 1974, when we looked at Fischer-Tropsch for the Project Independence Blueprint effort, that Fischer-Tropsch had a place in synfuels production plans. The product has some very specific advantages. Environmentally it has virtually no sulfur, nitrogen, or particulates; it also tends to be more aliphatic.

It tends to be a high-cost product, which means that its primary fuel application is as a high-value product such as gasoline or LPG or petrochemical feedstocks.

If your target is to produce essentially a nil content heteroatom product, a very pure and very light product, Fischer-Tropsch is essentially competitive with the direct route. At least this is the way it has come out the several times that we have looked into it.

Conversely, we say that direct liquefaction should be a lower-cost alternative when you are looking for a heavy fuel, such as a boiler fuel, where purity is not required.

In my opinion, they each have a field of application. For some reason, Fischer-Tropsch has not had that much public attention in the United States. We have been involved in it with our work for the Department of Energy, who reported that they received questions regarding why the government programs ignored Fischer-Tropsch. So we were asked to develop preliminary designs based on that SASOL work, which we did in 1973 through 1975.

In the Project Independence Blueprint, Fischer-Tropsch was not included in the first round of assessments. When Seatek looked at it, they said, "How can you complete Project Blueprint without looking at Fischer-Tropsch?" We were asked to develop an opinion on Fischer-Tropsch within about two weeks, which we did.

To summarize, based on the preliminary designs we have developed. we have taken the position that one really can't afford to ignore Fischer-Tropsch, and it will have a field of application, as will direct liquefaction processes such as SRC, H-Coal, and EDS.

Vernon Weekman, Mobil Oil: We recently completed a detailed study comparing Fischer-Tropsch with the methanol-to-gasoline process, which is in a DOE report now available to the public. We found when we were looking at a very high-quality gasoline product as opposed to petrochemicals, that the methanol-to-gasoline route was about 30 percent cheaper than Fischer-Tropsch in terms of capital cost. This is reflected in gasoline that was 25 to 30 percent cheaper to produce.

Mr. Princiotta: Do you feel that Fischer-Tropsch is equally competitive with some of the direct processes, such as SRC-II and the EDS processes, for gasoline?

Mr. Weekman: Jim answered right, we are in a different ball game. If you are looking at boiler fuels, I think there is no competition for EDS or SRC. If you are looking for high-octane gasoline, I think we will see that the indirect route, such as methanol to gasoline, will be the cheaper route.

Mr. O'Hara: If I have not brought the Mobil-M gasoline into perspective, I apologize. We have looked at it several times, once for the Department of Energy, and have a great deal of respect for it. Environmentally, it fits into that category of being relatively clean. The product purity and the quality become factors, too. Certainly, the M gasoline and the Fischer-Tropsch have to be considered, at least in our judgment, for that kind of an application.

Mr. Princiotta then introduced Donald Jackson of Gulf Mineral Resources

Gulf Oil Plans in the Area of Coal Liquefaction: Donald Jackson, Gulf Mineral Resources

I am going to make a few remarks this morning about the current development of SRC-II. But I should also say that we are interested and involved in oil-shale activity with the Rio Blanco partnership with Standard.

Regarding SRC-II, I'd like to spend a few minutes this morning talking about some of the products, potential applications, and interests, as well as environmental aspects, rather than the design of the facility itself.

Let me presume that everyone is familiar with the SRC-II process developed in the early 1960s.

Originally SRC-I was developed as a deashing technology, later expanded with desulfurization goals, and then ultimately developed as a liquefaction process known as SRC-II, using the active mineral matter (iron sulfur compounds) with the recycle of the heavier portion of the reactor effluent.

The hydrocracking results in a broad-range product spectrum, principally aromatic, nitrogen-containing low-sulfur distillates recovered through a distillation step.

The remaining residue is gasified for manufacture of synthesis gas to produce make-up hydrogen. The inorganics are converted into an inert slag for disposal.

The facility where most of the pilot experience has been gained is in Fort Lewis, Washington. The SRC pilot plant has operated for approximately three years in an SRC-II mode.

The current proposed project with the Department of Energy involves the design, construction, and operation of a 6,000 ton-per-day coal feed module plant, producing approximately a 20,000-barrel-equivalent product slate, which would be based on an approximately hundred-fold scale-up from some critical equipment at the Fort Lewis Pilot Plant. The current testing of additional equipment items will continue for the next several years at this pilot plant in support of the demonstration project.

Approximately 12,000 barrels of product have been produced at the pilot plant, about two-thirds of which either has been or is now being consumed in product testing of various kinds.

Table 21 compares the properties of SRC fuel oil with typical fuel oil products. Certainly the low viscosity, gravity, and pourpoint suggest it is a suitable fuel for use in industrial applications where they would be subjected to ambient conditions, where there is no access to the heating and pumping capabilities of a utility setting. We see this broad-range fuel primarily for applications in utility-industrial boilers, combustion turbines, and medium-speed diesels.

Table 22 summarizes the results of a significant test performed with approximately 5,000 barrels of the broad-range fuel at the 74th Street Station in Manhattan on the Con Ed System. The unit is a Combustion Engineering tangentially fired boiler (450,000-pound steam unit), with no special preparations or conditions other than a thorough check of the boiler prior to the test.

The concern was not just for boiler efficiency but also for emission performance. The recorded NO_x emissions of 175 to 300 ppm reflect the use of "staging" in which the air-fuel mixture was controlled. Controlling air flow from the lower ports permitted a fuel-rich and then a fuel-lean sequence in combustion, in order to reduce the flame temperature peaking and, therefore, reduce the NO_x formation.

Those results in a conventional boiler, again with no special preparation, would suggest that, at least for boiler application, NO_x control will be a reasonable and minimum-cost practice. It suggests that there is no need for additional hydrotreating of the fuel oil product for the specific purpose of removing nitrogen, which is a very costly procedure.

This test is for only one boiler configuration. EPRI is funding additional tests on different manufacturers' boilers over the next several years.

Additionally, the test results on particulate levels and other emissions were quite acceptable. As we said, 95 percent sulfur removal is a characteristic of the process itself, with about a 3 percent or more starting sulfur content in the coal.

Table 23 is a comparison of heavy metals contained in the original feed coal and in the product, with the removal reduction measured on a Btu-content basis. The significance of the low level in the fuel product relates to concerns about performance in combustion turbines and suggests that, again, these coal distillates may well be suitable in the turbine environment without further treatment required, subject to development of suitable NO_x control systems. Someone mentioned yesterday the Pratt and Whitney results on the rich-burn/quench test which, along with the somewhat similar results achieved by Westinghouse, are encouraging.

Again, with regard to controlling NO_x at the combustion point rather than further denitrogenation of the fuels, Mr. O'Hara from Parsons commented on the more attractive economics for those mild hydrogenation processes to produce coal distillates. That relative advantage exists only if, in general, these raw products can be utilized both effectively and in an environmentally acceptable manner without further processing.

In July of last year, DOE signed a contract with a group sponsoring SRC-I and with Gulf, through its P&M subsidiary, for SRC-II for a Phase Zero work scope.

Phases One, Two, and Three refer to design, construction, and operation. Phase Zero is a preliminary assessment in terms of design, environmental assessment, site acquisition, and market assessment of products from direct coal liquefaction with the SRC-II process.

To conduct this assessment, a number of other firms were enlisted to conduct both product testing and paper studies of application potential. As an example of the work that went on in assessing the likely application economics, one might look at the result of the utility studies. There certainly are parallels for the other application areas.

Figure 17 is a combined depiction of the system generation projections of four companies which represent, in general, fairly large utility firms with an existing mix of nuclear-, coal-, and oil-fired base and the intermediate capacity and some gas-peaking capacity.

The trends shown (and these studies were prior to TMI) suggested a continuing growth in base-load capacity (nuclear and direct firing of coal with FGD), a decline in utilization of existing oil-fired for baseload, a maintenance until the end of the century of oil-fired, intermediate capacity, and finally, a maintenance of oil- and gas-fired peaking capacity.

The only significant new technology generation option to occur in the period is the use of combined cycle facilities, some liquid-fuel fired (those being introduced first), and subsequently coal-to-gas. Even severe public policy constraints on the use of petroleum don't seem to change this pattern substantially, suggesting that the economic attractiveness, at least in the utility sector, for a liquid fuel derived from coal, may be substantial and may continue. This is certainly true for a fuel that could be utilized in combustion turbines. The improved efficiency of the combined-cycle turbine is the primary reason why it is projected as the significant new plant option.

In Figure 18, the same data are used to depict the market application for coal-derived liquid fuels in the boiler and the turbine applications. It suggests that the initial potential for coal liquids, if available, would be in existing oil-fired capacity. Today, this is approximately one and one-half million barrels a day. As you know, the Administration's proposed program to reduce that by one-half by 1990 would leave -- if one looks at the plans for that being accomplished by the industry -- most of the existing oil-fired intermediate capacity.

One of the interesting things that these studies revealed is the economics of maintaining and rehabilitating existing oil-fired capacity, extending the useful equipment life. Given the availability of a liquid fuel, in this case coal-derived fuel, maintaining and rehabilitating that equipment is more attractive than abandoning it and replacing it with new capacity, generally base-load direct coal fired. The result is large dollar motive to retain existing liquid- or gas-fired power plants for longer than in the past.

If there is a coal liquid fuel available to the power producer, there is an indirect price at which the utility would abandon the existing facility and replace it with a new direct coal-fired plant rather than extend the life of the existing oil-fired plant. Recent studies have shown cases where this price of "indifference" is as high as $50 a barrel. This is some indication of the market for coal-oil liquids in the utility sector. It also gives an indirect indication of how fast the Administration's $5 billion allocation to help the utilities convert to coal will be consumed.

Gulf is currently involved as a contractor in a program to design, build, and operate a demonstration plant for the SRC-II process. The word "demonstration" refers to the fact that it is not a commercially economic venture; it is intended to employ equipment of commercial size and character. That means that a commercial effort following the demonstration could employ, in general, the same equipment and design practices. Of course, there will be some increase in capacity and learning so that it wouldn't be an exact replicate.

The prototype nature of equipment in this plant is evident in several units. For example, the reactor vessels for the initial module will be as large as the process industry has employed to date. Operating conditions are approximately 2,000 pounds pressure and 830 to 870°F. Examples of prototype equipment include the gasifier and the oxygen compressors as well. There are approximately 14 different areas within the plant which will employ prototype equipment.

Mr. Princiotta: Could you explain why the commercial plans seem to call for production of a wider range of products than your demonstration plans?

Mr. Jackson: In the demonstration plant, there is, by design, an effort to restrict the products delivered across the fence to relatively simple utility fuel substitutes, in this case, the fuel oil, LPG, SNG, etc.

Mr. Princiotta: Why is that?

Mr. Jackson: That's for a couple of reasons. Number one, the utility industry is committed financially to support the project through a purchase agreement.

Number two, the subsequent processing for recovery of alternative product slates involves technology, generally, that is not entirely new, for which demonstration, one might argue, is not necessary.

Third, the size of those streams in the first demo plant are rather small and not very economic to process further. There is one exception. In the demo plant, a hydrotreater will be included for treating the naphtha. The naphtha will then be moved to a refinery for reforming into high-octane gasoline, to demonstrate its application as a transportation fuel. In the commercial plant, quantity of product (at a five-fold increase) would be significant enough to warrant further processing and some upgrading.

There are some 25 East Coast utilities that have now proposed to purchase the demo plant product at the then-market price of low-sulfur fuel oil, plus $2 a barrel. This is a DOE program and Gulf is negotiating to become a cost-sharing participant in it.

The Government of Germany is planning to be involved to the extent of 25 percent of the projected capital cost. The Goverment of Japan is currently carrying out discussions to participate in a similar manner for 25 percent of the costs.

We would anticipate that the demonstration plant will proceed with the first full mechanical checkout and starting operations in late 1984. An adequate demonstration period of operations will be necessary to assess the viability of expanding to a full-sized facility or of using similar process technology to build a full commercial-sized coal refinery.

Table 24 is a summary of approximate product yields that would be expected. I think these are similar to those of all direct liquefaction processes. Of course, the product slate is a function in part of the operating condition of the coal feed as well as the product used for providing makeup hydrogen and refinery fuel.

I believe that the concept of using partial oxidation on the residue is attractive both to dispose of the residue and to generate synthesis gas. Where there is synthesis gas in excess of that required for hydrogen make-up, one can even envision using syngas-to-liquids technologies for making distillate products.

The demonstration facility is located on a 2,600-acre site, four miles east of Morgantown on the Monongahela River. It will use coal from the Panhandle area. Experiments have been made on most of the major Illinois, Kentucky, and Pittsburgh-seam coals and performances seem, for the most part, acceptable.

Again because SRC-II currently, as discussed, utilizes contained sulfur compounds as the catalyst, high-sulfur bituminous coal is therefore desired. Experimental work has been reported on the addition of expendable catalysts for other coals.

Figure 19 is an overall long-range projection for the disposition of products for direct coal liquefaction.

The medium-speed diesel application is worth commenting on. This country uses medium-speed diesels in railroad locomotives. Approximately 400,000 barrels per day of distillates are currently consumed in the locomotive application. Their mass and size are such that they may handle the aromatic nature of these coal distillates (with their low octane rating), unlike a high-speed diesel (auto or truck).

Certainly coal naphtha will find its way into the gasoline pool, in order to utilize the aromatics. Proper treating and reforming will yield a high-octane fraction which can be used as blend stock.

Dale Denny, EPA: You mentioned a break-even cost for conversion costs -- the cost for conversion of oil to coal for utilities supporting $50 per barrel. What year was that?

Mr. Jackson: That was in 1979. I indicated that as an extreme case. We found one plant situation, at a New England site, where they determined they could afford to pay that much to have liquid fuel, to continue to be able to operate the plant rather than to abandon it and replace it with new direct coal-fired capacity.

Mr. Denny: That's based on a cost this year?

Mr. Jackson: That's based on a cost this year. Incidentally, with regard to product cost on a Btu base for all fuel products, not by-products, the estimates submitted to DOE as part of the Phase Zero contract were that coal liquids could be produced in commercial facilities in the 1990s (if demonstration is accomplished and if the component materials, construction, equipment, and instrumentation improvement, as projected, can be realized) for $25 to $30 a barrel in today's dollars.

Fred Glaser, DOE: It's been reported recently that the cost of the SRC-II project has doubled. I realize conventional scaling factors are probably not appropriate here, but if one did apply those for a five-train commercial

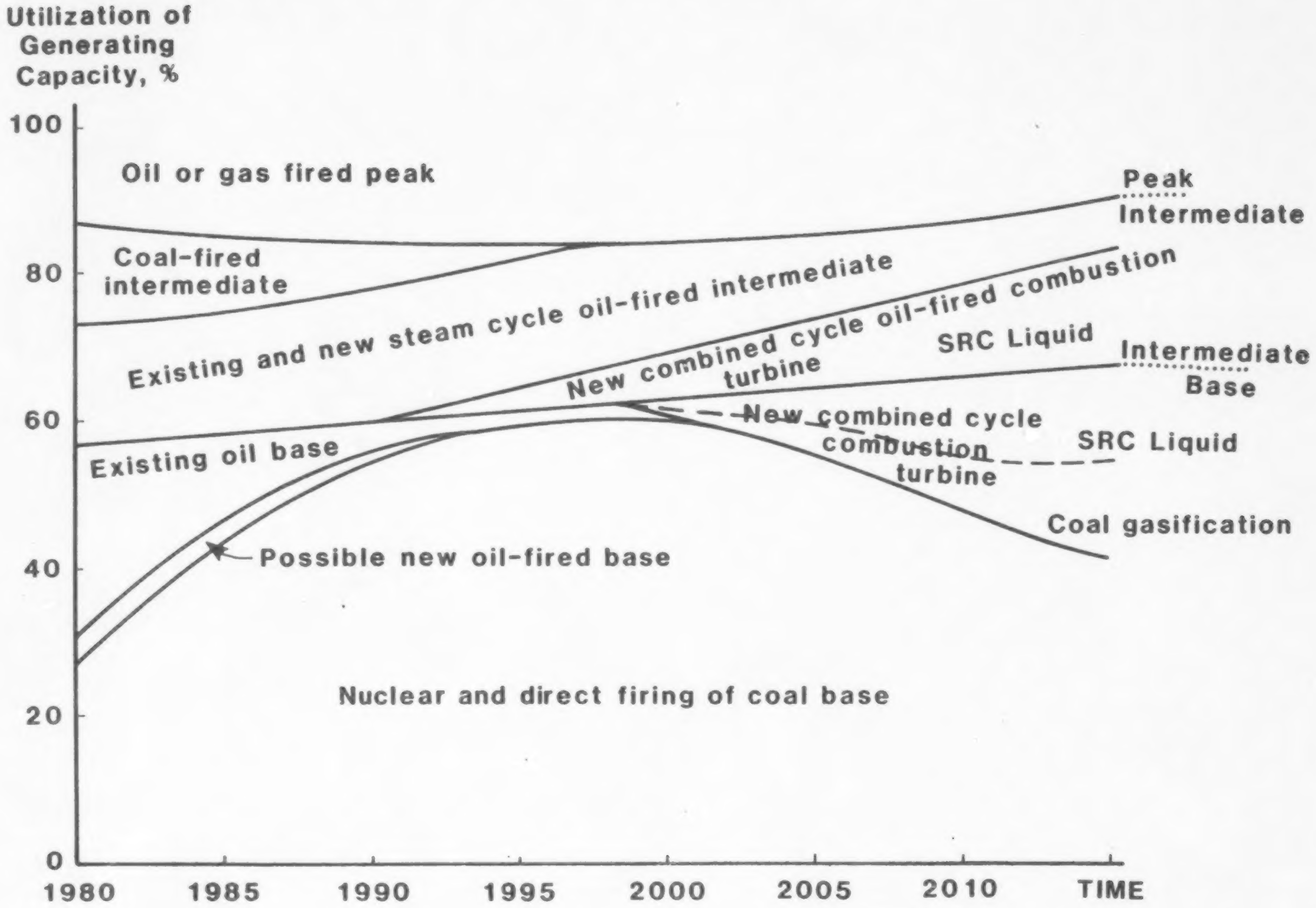


Figure 17. Conceptual Composition of System Load with Time

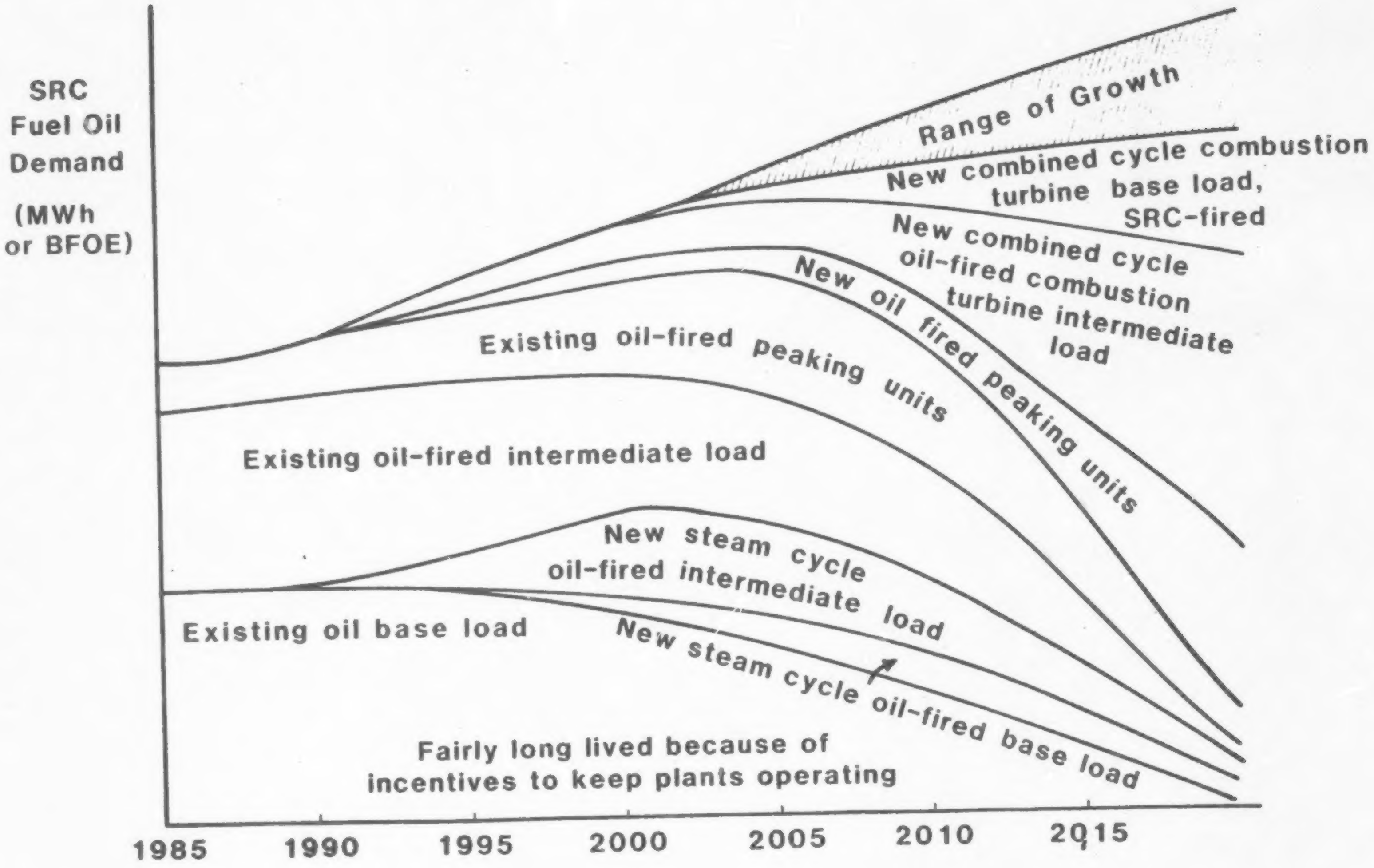


Figure 18. Conceptual Electric Power Generation Demand for SRC-II Fuel Oil

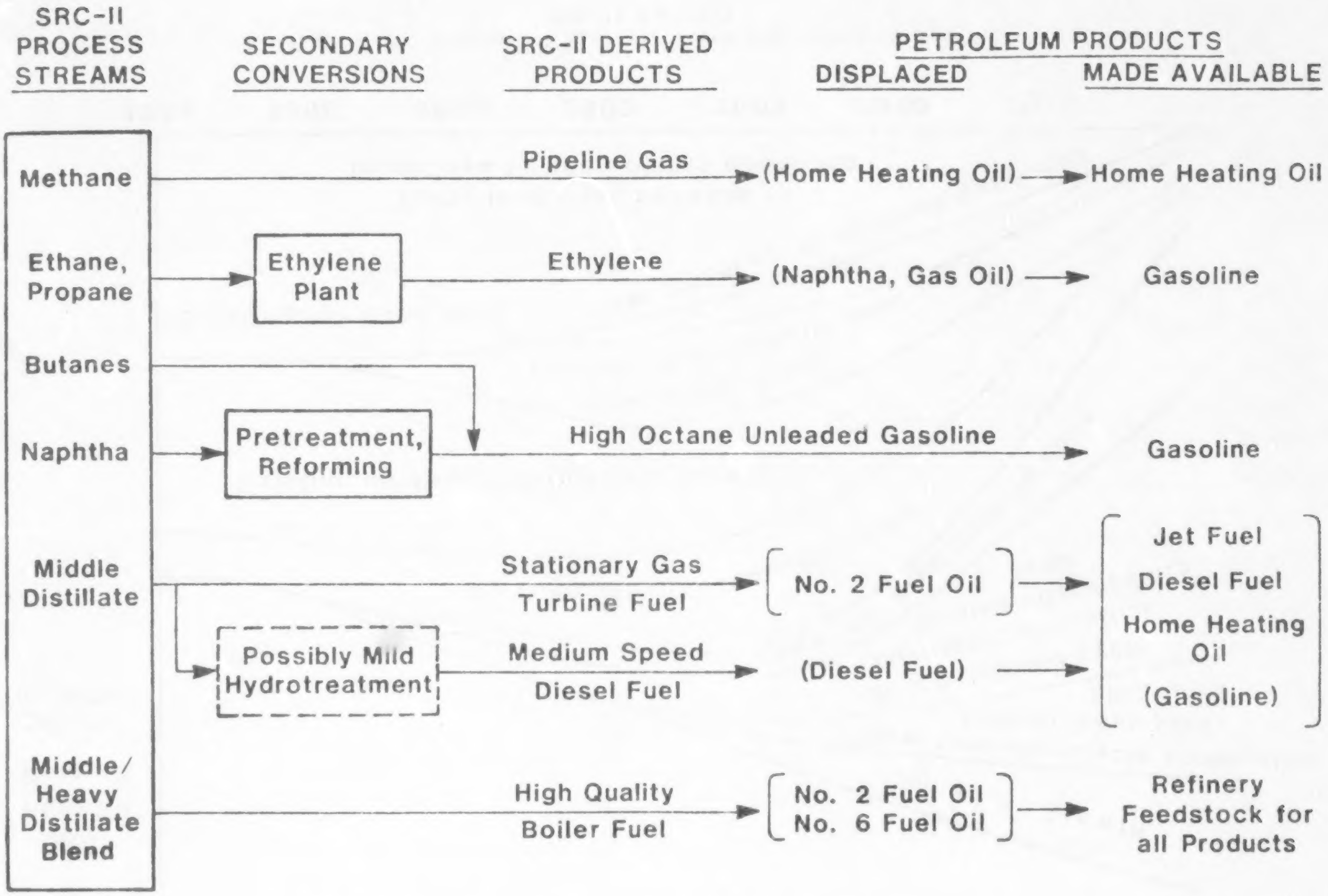

SRC-II PROCESS STREAMS
SECONDARY CONVERSIONS
SRC-II DERIVED PRODUCTS
PETROLEUM PRODUCTS
DISPLACED
MADE AVAILABLE
Methane
Pipeline Gas
(Home Heating Oil)
Home Heating Oil
Ethane, Propane
Ethylene Plant
Ethylene
(Naphtha, Gas Oil)
Gasoline
Butanes
Naphtha
Pretreatment, Reforming
High Octane Unleaded Gasoline
Gasoline
Middle Distillate
Stationary Gas Turbine Fuel
No. 2 Fuel Oil
Possibly Mild Hydrotreatment
Medium Speed Diesel Fuel
(Diesel Fuel)
Jet Fuel
Diesel Fuel
Home Heating Oil
(Gasoline)
Middle/ Heavy Distillate Blend
High Quality Boiler Fuel
No. 2 Fuel Oil
No. 6 Fuel Oil
Refinery Feedstock for all Products

Figure 19. Projection for Disposition of Products for Direct Coal Liquefaction

TABLE 21. SRC FUEL OIL PROPERTIES COMPARED WITH TYPICAL FUEL OIL PRODUCTS

	SRC FUEL OIL	TYPICAL GULF PRODUCTS NO. 4	NO. 5	NO. 6
Gravity (°API)	8.3	23	19	12
Viscosity (CS, 100°F)	4	14-20	150-200	900
Flash Point (°F)	>150	←	>150	→
Pour Point (°F)	-23	<-20	<+10	<+60
Sulfur (%)	0.25	1.00	1.8	0.3-2.2
Sediment (%)	< 0.03	0.05	0.05	0.25
Carbon Residue (%)	< 0.3	5.5	6.4	6-16
Ash (%)	0.015	0.01	0.02	0.05
Nitrogen (%)	1.0	0.2	0.3	0.4
Net heating value (BTU/Gal.)	148,000	135,000	137,000	141,000

TABLE 22. LARGE-SCALE SRC-II FUEL OIL BURN TEST RESULTS

	EPA REQUIREMENTS	TEST BURN RESULTS
NO_x	400 PPM	175-300 PPM
Sulfur	85% Removal	95% Removed
Particulates	.03	<.03 (No precipitator)
Hydrocarbons	---	< 3 PPM
CO	---	< 50 PPM
SO_3	---	< 1 PPM
Boiler Efficiency	---	Comparable to petroleum fuel oil

Coal liquids (SRC-II) are in most respects superior to residual fuels. They are distillate fuel oils and can substitute for petroleum fuel oils in the more restrictive environments.

TABLE 23. COMPARISON OF SRC FUEL OIL AND COAL

	Coal	SRC Fuel Oil	Fraction Remaining (BTU Basis)
Heating Value (BTU/Lb.)	11,500	17,300	
Sulfur (Wt. %)	3.0	.25	.06
Nitrogen	1.5	1.0	.44
Oxygen	8.0	3.8	.31
Ash	12.0	.01	.0005
Nickel (PPM)	16	.1	.004
Vanadium	30	.1	.002
Titanium	530	1	.001
Calcium	330	2	.004
Silicon	2300	10	.003
Cadmium	2.5	.01	.003
Sodium	140	.5	.002

TABLE 24. TYPICAL SRC-II PRODUCT SLATE

DEMO MODULE WITH 6,700 T/SD COAL FEED AND COMMERCIAL PLANT (FIVE MODULE) WITH 33,500 T/SD HIGH-SULFUR COAL FEED

PRODUCT	DEMO MODULE	COMMERCIAL
Methane	45 MM SCF/D	50 MM SCF/D
Ethane/Propane	--	3,000 T/D
LPG (C_3, C_4)	4,000 B/D	--
Butane	--	300 T/D
Naphtha (C_5 - 350°F)	--	17,000 B/D
Fuel Oil (350° - 900°F)	11,500 B/D	56,000 B/D
Ammonia	30 T/D	180 T/D
Sulfur	160 T/D	1,200 T/D
Phenols	7 T/D	240 T/D
Thermal Efficiency	65% or less	72%

plant, the price would be over $4 billion, which of course is not competitive, compared to other reported alternatives. I am wondering if you have a new or a current estimated price for your commercial-sized plant.

Mr. Jackson: The $25 to $30 I just referred to is the current estimate. That is the estimate that was submitted at the same time that the current estimates for the cost of the demonstrational plant were submitted. Those were in the order of $800 million for the demonstration plant in today's dollars. In the same study, a full multi-train commercial SRC-II plant, subject to a number of qualifications, was estimated at $1.75 billion, in today's dollars.

A number of other estimates have been quoted by various organizations, including DOE. Some of them included various contingencies with which I am not familiar. Some of them include estimates of escalation built in. Certainly, if we continue with the kind of escalation there has been, that investment cost could be half again as high in as-spent dollars.

It is of interest to note that to some extent these capital-intensive facilities offer some immunity both from the volatile petroleum import market and future inflation. Capital amortization will represent almost one-half the product cost in these synthetic fuel projects.

Norbert Jaworski, EPA: I'd like to follow up on oil and coal switching. You said $40 or $50 a barrel. That's assuming a certain availability of oil at any price from OPEC? You are talking of 1990 before you plan to be commercial and you are banking on technology in the future versus conventional combustion which you have today.

Mr. Jackson: Yes, although combustion tests of coal liquids have been successful. I think with regard to making these fuels on a commercial basis, however, that's correct.

Mr. Jaworski: Are you saying that banking on the existing climate, the cost-existing climate, you are keeping those going with the SRC-II? That assumes then that we have an available source of oil up to 1990?

Mr. Jackson: For some of the generating plants -- absolutely. I think one of the shortcomings of the Administration's current program is the dichotomy of trying to address and encourage the development of a coal-derived liquids industry to supply synthetic fuel oils and at the same time trying to curtail, obviously for a variety of reasons, the continued use of fuel. The problem is, if capital equipment is changed as a result, you may have foregone the option to utilize the coal liquids. My point simply was that even with the pressures to switch, such as the Administration's bill to halve the oil consumption of the utility industry, there are a number of facilities still out there where the increment is so substantial that a substantial amount of oil-fired capacity in intermediate and peaking duty will be in existence in that time frame.

Mr. Jaworski: This is strictly economics rather than a projected world supply and OPEC and all those nice little things that could happen?

Mr. Jackson: Yes. It is an economic view over the time period assuming escalating import oil prices.

Vernon Weekman, Mobil Oil: Do you have any experience with gasifying the residual material you talked about?

Mr. Jackson: Texaco has performed test runs on SRC-II vacuum bottoms in a pilot plant gasifier. I believe Exxon has taken samples of the residue from their EDS process and gasified them as well.

Fred Glaser, DOE: Your bar chart showed that the startup of a commercial facility could be as early as 1990. I am wondering if that estimate presumed any actions by EPA, especially with regard to carcinogenicity problems, the particulate-type issues that we normally talk about when we talk about SRC-II, or is that a conservative estimate?

Mr. Jackson: I guess I am not worried about the particulates as much as the potential carcinogenicity of some of the product. It does not assume any extraordinary delays as a result of action by the Agency.

Mr. Princiotta: Could you give your opinion of some of the statements that Mr. O'Hara made about the relative share of the market that a direct liquefaction process such as yours might achieve relative to SASOL and others? Would you agree that if one is interested primarily in the high-grade products such as gasoline and the lighter end of the diesel spectrum that the indirect processes are probably going to be competitive?

Mr. Jackson: In my opinion, it would seem appropriate to pursue several directions.

Let's say the oil to synthesis gas and synthesis gas to liquids provides higher-cost but also higher-value products. This can be combined in a complementary nature of direct liquefaction to address perhaps more economically some of the lower-value products.

We also envision that the large synfuels plants will tend to look ultimately like refineries rather than single-product facilities.

Richard Eccles, HRI: Would you comment on the properties of the SRC-II fuel oil that was tested by Con Ed, perhaps in contrast to the SRC fuel oil which you described on some of your slides?

Mr. Jackson: The properties were almost identical. It was a broad-range fuel.

There has been some question about the relative distribution of the boiling range of that product. That's a technical point right now because we use a heavy oil as a seal flush at the pilot plant in Fort Lewis. So we don't think we get as much of a percentage of the heavier fractions as we would from the commercial plants.

We have restructured our blends in a variety of tests that are being performed now at a smaller scale to try and evaluate that specific question. Small tests of the heavier fractions only are suggesting acceptable results with regard to both combustion performance and emissions. This is very encouraging because the lighter fractions are more likely, ultimately, either to be hydrotreated and reformed for gasoline or jet fuel or at least used in turbine application and not boilers.

Mr. Eccles: What was the end point of the test fuel?

Mr. Jackson: About 900°F.

Mr. Princiotta: I wonder if you could comment on some of the results of the DOE and EPA studies of the relative toxicity of some of these products, particularly heavy-end products? Do you see this as being a real impediment for the commercialization effort? Have you studied the potential impact of TSCA on those products? Are there any other comments you want to make along those lines?

Mr. Jackson: I am not really qualified to comment on that. I will offer my opinion that the experience of the fairly comprehensive industrial hygiene programs at the Fort Lewis Plant has not reached that conclusion. At that pilot plant, so far there have been no instances observed of a cancer-related nature.

Now, that doesn't tell you what would occur in the absence of a good hygiene program, but it does suggest that with good hygiene, these fuels can be utilized in a healthy and safe manner, at least in industrial settings.

Mr. Princiotta: Is it your feeling right now that such industrial hygiene programs might be necessary for utilities or in other industrial sectors that might use your fuel products? Would you recommend that right now, for example, to your users?

Mr. Jackson: Certainly one would rather err on the side of safety at this point with the body of knowledge that exists. DOE is sponsoring fairly extensive toxicology and bioassay programs right now to get a greater insight into what concerns should exist.

Richard Passman, DOE: Concerning your date on commercialization with the incentives that are discussed by Congress and the Administration, do you think that that date will move ahead or is it paced really by the R&D status on your demonstration model?

Mr. Jackson: I think it's largely paced by the status of the demonstration plant. The purpose of the demonstration plant is not so much technology confirmation as equipment and large systems confirmation.

The design, construction, and successful operational integration of the equipment, as well as its maintenance and availability, are really key factors that would appear as impediments to any commercial plant investor. That is, because of the high capital nature of such facilities, a high on-line availability is required for a reasonably assured opportunity to market the products. That's something that has to be more fully demonstrated before, I think, such commercial investments will be made.

Some incentives will reduce that concern; for instance, the accelerated write-off of those investments reduces the length of exposure of the large capital. But one can only accelerate to a certain extent the preparatory measures for a commercial facility.

I think the key is the demonstration in the large, integrated full-scale equipment. It has involved equipment designers, manufacturers, fabricators, etc. It employs an operating system that has the control technology to assure long-term safe and maintainable operation.

James O'Hara, Ralph M. Parsons Co.: It appears to us that the designs both of pilot plants and demonstration plants are essentially forced to rely on equipment suppliers that have largely served the petrochemical and refinery industries. It would also appear to us that in certain parts of the coal liquefaction plants, there will be a transition period during which some items will be toughened and modified so that eventually there will be equipment items in certain parts of the plant that are specific to the industry, which don't yet exist. A total program requires incentives for involvement by the equipment manufacturers.

Looking at it from their viewpoint, is there a sufficient market out there, first of all, to justify commitment of their own private funds? Alternatively, is there a way to obtain public funds which would give them incentives?

In terms of this reliability -- and I can only speculate -- it's most important in the economics and is an area where there will be a transition.

Mr. Princiotta then introduced Harry Enoch of the Kentucky Department of Energy.

The State of Kentucky's Plans and Activities in the Siting of Coal Liquefaction Facilities: Harry Enoch, Kentucky Department of Energy.

I'd like to talk with you about some of the efforts of the State of Kentucky in the area of coal liquefaction. In addition to discussing our demonstration projects underway, I'd like to go into a bit of detail about the efforts we are now making in trying to site commercial-size liquefaction facilities and also to discuss some of the environmental aspects of those liquefaction processes.

First, I want to talk about the demonstration projects that are underway. The furthest along is the H-Coal pilot plant which is nearing completion in Catlettsburg, Kentucky. The pilot plant will use 600 tons a day of coal and will be operable in two modes, either the fuel-oil mode or the syncrude mode, to produce two different types of products.

The developer of this process is Hydrocarbon Research. Ashland Synthetic Fuels, a division of Ashland Oil, will be the operator of the plant; Badger Plants is the constructor.

The participants in this project are a consortium of government agencies and industries. The U.S. Department of Energy, the Kentucky Department of Energy, Ashland Oil, Mobil Oil, Standard, Conoco, and the Electric Power Research Institute are all involved in the project.

The plant is now nearing completion. It's essentially ready to go; only the coal-handling equipment needs to be constructed. Oil operations are expected to start up in January 1980. Coal operations are expected to begin in April 1980.

Three coals will be tested in the plant using the various modes: Kentucky and Illinois high-sulfur bituminous coals and a subbituminous Western U.S. coal, a Wyodak coal.

The next demonstration project is SRC-I or Solvent Refined Coal, which was originally in competition for funding with SRC-II. At this stage, it looks as if both projects will be funded.

This plant will be built as a 6,000 ton-a-day module and then scaled up to a commercial size at the site in Newman, Kentucky.

The original idea for SRC-I was to produce a solid boiler fuel for the utility industry. This would be a low-sulfur, low-ash fuel to help the utilities meet the New Source Performance Standards without requiring expensive control equipment. The process has undergone continuous refinement and is now capable of producing liquid products in addition to solid products and fuel gas.

The participants in this project are the Wheelabrator-Frye/Air Products joint venture, the Kentucky Department of Energy, and the U.S. Department of Energy. The State of Kentucky has provided some of the funds for construction of the plant. We also purchased the site for this plant.

The conceptual design has been completed and submitted to the Department of Energy; detailed engineering work is in progress now and will be completed in the middle of 1981; on-site environmental assessment work and the preparation of the Environmental Impact Statement are also underway. Construction is expected to be completed by the end of 1983 and start-up should take place six months after that. The schedule for commercialization of the plant assumes that the next two modules could begin construction within two years of the start-up of the demonstration module.

The third Kentucky demonstration project in coal liquefaction is our coal-to-ammonia project. This plant was designed to be a commercial-size ammonia plant that would use coal as its feedstock for hydrogen production. The process also will demonstrate the use of the Texaco gasifier with a high-sulfur bituminous coal.

The plant will use 1,900 tons a day of coal and produce 1,200 tons a day of ammonia. The participants in the project are W. R. Grace and the U.S. Department of Energy. Kentucky's role in the project was, again, to purchase the site. We also arranged and paid for the preconstruction monitoring at the site, which is in Baskett, Kentucky.

The preliminary design for the ammonia plant was submitted to DOE in July 1979. Shortly thereafter, DOE asked W.R. Grace to change the scope of the project to consider producing liquid fuels. All the emphasis in Washington this summer was on liquid fuels. Grace then came back with a proposal to build at that site a 30,000 ton-a-day plant to produce methanol from synthesis gas and then convert methanol to gasoline, using the Mobil-M process. Again, that would be based on the use of the Texaco gasifier.

Mr. Princiotta: No ammonia? Ammonia is out?

Mr. Enoch: Ammonia, apparently, is out. There were also some problems in the ammonia market. Liquid fuels is the project that DOE is waiting to act on.

Figure 20 shows the location of these demonstration plants in Kentucky. The H-Coal site in Catlettsburg, Kentucky, is in the eastern coal fields on the Big Sandy River. Newman is the site of the SRC demonstration plant. It lies on the Green River in the western Kentucky coal fields, as does Baskett, the site of the Grace project.

In addition to these, Ashland Oil is planning to construct an H-Coal commercial plant. This pioneer plant will use 20,000 tons of coal a day. Ashland is looking for a site for this plant in the Illinois Basin. The State of Kentucky is looking for suitable sites in the western Kentucky coal fields.

Kentucky is also interested in the development of commercial-size facilities using the SASOL technology, the indirect liquefaction route using Lurgi gasification and Fischer-Tropsch synthesis. We are interested in this for a number of reasons, but the most compelling is that it is proven technology, with a plant up and running in South Africa. This would provide the fastest path to commercialization. We are interested in speeding up the process of commercialization of coal liquefaction.

Kentucky has been actively trying to attract coal liquefaction projects to the state for a number of years now. Since day one, we have been involved in the siting process for these liquefaction plants.

We feel it would be advantageous to the state and to industry if we find the most suitable sites in the state for locating these large facilities. We have been identifying and cataloging potential sites based on a number of general criteria, including availability of land, water, coal supply, and transportation. Using this catalogue of sites, we can go back and fill in detailed information, based on the specific requirements of commercial facilities. Plant design considerations would include the air emissions, the amount of solid waste produced, and the numbers of people to be employed constructing and operating the plant.

After we have a good idea of the specific requirements for a plant, we go through the screening process and try to choose from the potential sites the one that best fits the requirements for this plant, asking such questions as: Does the amount of land available meet the land requirements? Is there enough water available for this specific process?

So far, we have assumed that these sites must meet all the primary criteria. We will, in the next year, begin to examine a number of the alternatives to satisfying those primary criteria. For example, if the site that we are looking at does not have sufficient land for both the plant and a waste disposal site, we would look then for sites with the potential for off-site waste disposal. If a site is not located on a river and cannot supply enough water to the plant, we will consider the possibility of moving water in: pumping water in from the river or using groundwater or a combination of surface waters and groundwater. So, we will consider a number of alternatives to locating the sites on rivers.

In addition, the markets will have to be matched up against the product slate. We are most interested in trying to find markets for some of these products in Kentucky. We would like to see as much of the product as possible stay in the state.

We are also beginning to consider the impacts, environmental, social, and economic, of building these plants at specific sites. If we start in this game early enough, we will be able to match a specific plant to a specific site, based on these considerations as well, which has not really been done that much previously.

In performing an impact assessment, we will be looking at such factors as air quality: Would the plant be able to meet the air quality standards? Is there enough increment available at the site for the air emissions? Would the plant have an adverse impact on a non-attainment Class I area?

Similarly, questions will be asked about water quality, waste disposal, and land use. We will also collect and analyze information dealing with terrestrial and aquatic ecology, try to identify historical and archeological sites, and also consider some of the social and economic aspects of constructing these plants at various sites.

Bill McCarthy, EPA: Are you working with EPA and ORBES (Ohio River Basin Energy Study) on this?

Mr. Enoch: The answer is no.

The ORBES study is a large, integrated assessment of all energy facilities in the Ohio Basin. We are keeping abreast of what they are doing, but we are not working with them. We are going to expand our analysis to do something similar to ORBES study. We are going to do an integrated impact assessment of all the synfuel plants that might be located in the state.

There is a chance that in the 1980s, Kentucky could have three to five commercial-size liquefaction facilities under construction. It's important to start now to determine the impact of the aggregate number of plants.

A related question is how many plants could Kentucky presumably support in the future: What is the long-range projection for this? We will be combining this with the location of power plants in the Ohio Valley and the use of some of the information taken from ORBES.

Figures 21 and 22 show the coal fields and the major water supplies in Kentucky.

On the right in Figure 21 is the eastern Kentucky coal field, which is part of the Appalachian coal field; on the left is the western Kentucky coal field, which is part of the Illinois Basin.

We have, in addition, four major rivers capable of supplying the large amounts of water that are needed for synthetic fuel plants. There is sufficient water all along the Ohio River. Also, there are portions of the Tennessee River, the Cumberland River, and the Green River that have sufficient water for synthetic fuel plants.

Our primary area for looking at sites has been in the western Kentucky coal field because of the availability of large amounts of high-sulfur coal, the presence of large amounts of water, and the good transportation modes that are available for the coal and also for the markets.

I mentioned that we are going to look at some alternative siting opportunities in Kentucky. In the next year, we will begin to investigate the possibilities of moving coal a little farther out of the coal fields to other parts of the state. We will also look at the possibilities for building sites off rivers. This would include the possibility of mine-mouth operation, for water then may have to be pumped in from the river.

So, we think Kentucky has a number of very good sites in the western Kentucky coal fields. We think there may be adequate sites on the Ohio River bordering the coal fields and in some other areas contiguous to the coal fields around the state.

A recent report issued this summer by the Department of Energy tended to disagree with our analysis of the availability of good sites in Kentucky. The report, Environmental Analysis of Synthetic Liquid Fuels, attempted to determine if there were any environmental constraints to meeting an accelerated program of liquid fuels commercialization.

The report created a stir in Kentucky because they didn't identify any sites in our state. I want to discuss how they arrived at that conclusion and I want to tell you what went wrong, beginning with Table 25.

The study was aimed at determining if rapid commercialization was possible by identifying adequate sites (as counties). They did identify 41 counties in the United States that could accommodate a 100,000 barrel-a-day direct liquefaction facility. Twenty-seven of those sites were in the Western states. Fourteen were east of the Mississippi River: five in West Virginia, one in Pennsylvania, and eight in Illinois. Kentucky was conspicuous by its absence from the list.

Table 26 shows how they arrived at that surprising conclusion. The columns show the screening that they went through to determine where these sites would be. They started out with all the counties in the coal-producing states. Then they eliminated all those counties that did not have 500 million tons of coal reserves. This dropped the number of adequate counties in Kentucky from 120 to 15. The next column screened out all counties that were within 50 miles of a non-attainment area. That removed the remaining 15 Kentucky counties.

I'd like to discuss Kentucky's reaction to this. First of all, the reason stated why these plants could not be located in Kentucky was that there were too many environmental problems. Table 27 indicates, however, that 105 counties were ruled out because they didn't have what was thought to be an adequate coal reserve. Most of them were not ruled out for environmental reasons.

The other 15 were eliminated for air quality. We honestly felt that they were overly conservative in their air quality criteria. I'm not sure it's reasonable to remove from consideration any site within 50 miles of a non-attainment area. This is probably very far off. A reasonable limitation would be 25 miles or possibly less.

Figure 21 shows the 15 counties that were determined to have adequate coal reserves. They are outlined within the coal fields of eastern

Kentucky and western Kentucky. The peculiar thing is that the borders can be drawn differently. For example, Butler County and Grayson County combined would have over 500 million tons of coal reserves. In eastern Kentucky, Knox County and Bell County combined would have over 500 million tons of reserve.

So it looks as if a geographical fluke eliminated most of Kentucky from consideration. This is brought out even more convincingly in Figure 23, which shows the size of some of the counties in the Western states where most of the sites were found. All of the counties are much larger than anything we have in Kentucky. We have too many counties.

For example, Table 28 shows that Sweetwater County in Wyoming has nearly 10,000 square miles. That's larger than the entire eastern Kentucky coal field. In fact, it's larger than the states of Massachusetts and Rhode Island combined.

I'm not sure it was fair to rule out 105 counties just because they didn't have enough coal. We feel that there is good transportation from the coal fields by rail and by river to justify location of plants in other areas. We feel the coal supplies would be adequate there.

Figure 24 identifies Kentucky's non-attainment areas. Most of these are non-attainment areas for particulates. The particulate problem in Kentucky is largely due to non-traditional pollutants rather than to point-source emissions. The pollutant sources are farming and mining operations, unpaved roads, and reentrained dust along the highway. It doesn't help that the state locates many of their monitors right along the highways.

If EPA reconsiders the particulate standard and issues a standard for respirable particulates instead of total particulates, it might help us somewhat with these non-attainment areas. Most of these non-traditional sources emit large nonrespirable particulate types that may not be associated with any adverse health effects. It is the small particles that usually emanate from point sources that are the major cause of health problems with particulates.

The really big problem is the short-term average. Those short-term standards can only be exceeded once a year. If you go out and build a plant and put up a monitor next to a field that someone is farming, you are going to be in a non-attainment area because there is no way that a farmer is not going to set that particular monitor off at least two days in a year. We would favor EPA reissuing the particulate standard to be a respirable standard.

Our situation with respect to sulfur dioxide is also a little unusual. Kentucky has five areas that were designated as non-attainment areas for sulfur dioxide, not because of any monitored violation, but because the Kentucky Department of Natural Resources and Environmental Protection did some model studies and determined that the monitor should have been violated.

EPA Region IV accepted that argument and did, in fact, classify those areas as non-attainment. In the State Implementation Plan, they assigned lower emission standards to coal-fired power plants in this area so that the modeled violations would not occur. In fact, most of the power plants have already met the new emission standards and those non-attainment areas are being reclassified.

We don't think the air situation in Kentucky is nearly as bad as some people might think. It is not really as bad as DOE might have thought when they did their analysis.

A lot of people have gone around our state and maybe yours telling us that if you think the emissions from power plants were bad, wait until you see those from the synthetic fuel plants. They are going to be much worse. Frankly, we just don't believe that's true.

I've tried to make some calculations and do some comparisons to see what the numbers look like. First of all, it depends on what kind of power plant the synthetic fuel plant is compared to.

In Table 29, I have taken a typical 1,000 megawatt power plant without emission controls that would use 10,000 tons a day of high-sulfur coal. That plant would emit about 700 tons a day of sulfur dioxide. We had a lot of those in Kentucky.

If the power plant was built after 1971, it had to conform with the New Source Performance Standards and the emission limitations that were set at that time. This plant would have much lower emissions of SO_2 and particulates. We have a few of these power plants in Kentucky.

Any new plant built after the effective date in 1978 would have to comply not only with the emissions limitations but also with the percent reduction of pollutants. The amount of SO_2 and particulates released from these new plants will be very low compared to emissions from existing power plants.

In Table 30, I have tried to compare the amount of SO_2 and particulates from a coal-fired power plant with those from a number of synthetic fuel processes. No. 1 shows the emissions from the coal-fired power plant and No. 2 indicates the emissions from the H-Coal plant operating either in the fuel oil or the syncrude mode.

The design data that we looked at assumed that the steam and utilities for the H-Coal plant would be provided by burning clean fuel that was produced in the process. The emissions from such a plant would be very low: 8.5 tons a day of SO_2. That is an order of magnitude less than that emitted by the cleanest power plant that could be built under the New Source Performance Standards.

The particulate emissions are not given in this report, but I would calculate, based on the process they went through, that they would be a little less than one ton per day.

If the electricity and steam were produced by the burning of high-sulfur coal, the SO_2 emissions could be expected to double, reaching 16.5 tons a day, which is still considerably less than any power plant.

The emissions aren't very different in the syncrude mode. Similarly, the designs for a Hygas plant and for a coal-to-methanol-to-gasoline plant also project very low sulfur emissions compared to power plants.

The SRC-I design that Wheelabrator-Frye/Air Products has submitted to DOE shows very low levels of SO_2 and particulates, again because they plan to burn clean process-derived fuel gas for their heaters and for steam production. The reason for this seems fairly straightforward: There are very low sulfur emission levels from the processes.

You can see from Table 31 that most of the sulfur and particulates emitted result from the operation of the coal-fired boiler. In the coal-to-methanol-to-gasoline design by the Badger Company, 97 percent of the SO_2 emissions and 96 percent of the particulate emissions are derived from the boiler flue gas. The other processes contribute very little to the emissions.

You can only remove about 90 percent of sulfur from the coal-fired boiler but you can do better than 99 percent removal from a process. This indicates that, in fact, synthetic fuel plants may be much cleaner than power plants.

Dominic Palazzo, Mobil Oil: Are there actually people who are interested in constructing an indirect liquefaction plant in Kentucky?

Mr. Enoch: I can't comment in much detail. We would be interested in attracting an operator for such a plant in Kentucky and will be involved in trying to get such a plant in the near future.

Jack Farmer, EPA: You indicated in Table 30 that the SO_2 emissions from SRC-I, for example, would be very low.

What would happen if you located a power plant burning the SRC-I fuel right next to that plant? Would the emissions go up significantly?

Mr. Enoch: Well, of course, the SRC was designed to allow the power plant to meet these standards. So I am not sure what your question is. A power plant combined with a synthetic fuel plant would, of course, have higher emissions.

Mr. Farmer: Weren't your emission estimates only for the process to make SRC-I?

Mr. Enoch: That is right. They did not assume any burning of it.

Mr. Farmer: SRC-I still has sulfur in it?

Mr. Enoch: Right.

Mr. Farmer: If you have a power plant burning the SRC-I right next to a plant making the SRC-I, do the emission estimates for that air go up?

Mr. Enoch: Okay. We should probably do that comparison to see what those numbers look like. I am going to predict that they are going to look better than the power plant for the same reason: that processing that fuel you have a 99 percent sulfur removal --

Mr. Princiotta: Not on SRC-I.

Mr. Enoch: That's not 99 percent removal in the product, rather only 1 percent of the sulfur is vented in the process. There is only about 1 percent. It's reduced to about .6 percent sulfur in SRC-I, so we have to do that comparison.

Mr. Farmer: I think the SRC-I process was hurrying around to get the 85 percent.

Mr. Princiotta: There are more emissions from the combination of the SRC plant and the boiler because SRC-I is not as effective on most high-sulfur coals.

Gary Fowler, Energy Resources Center, University of Illinois: I am a co-principal and investigator, one of 13, on the Ohio River Basin Energy Study (ORBES).

The reason the Department of Energy in Ken-

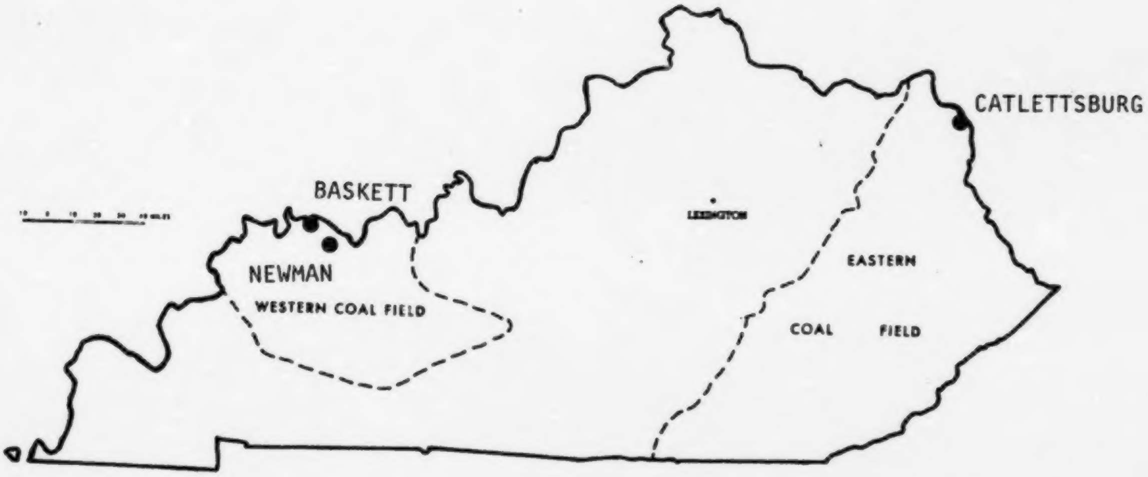
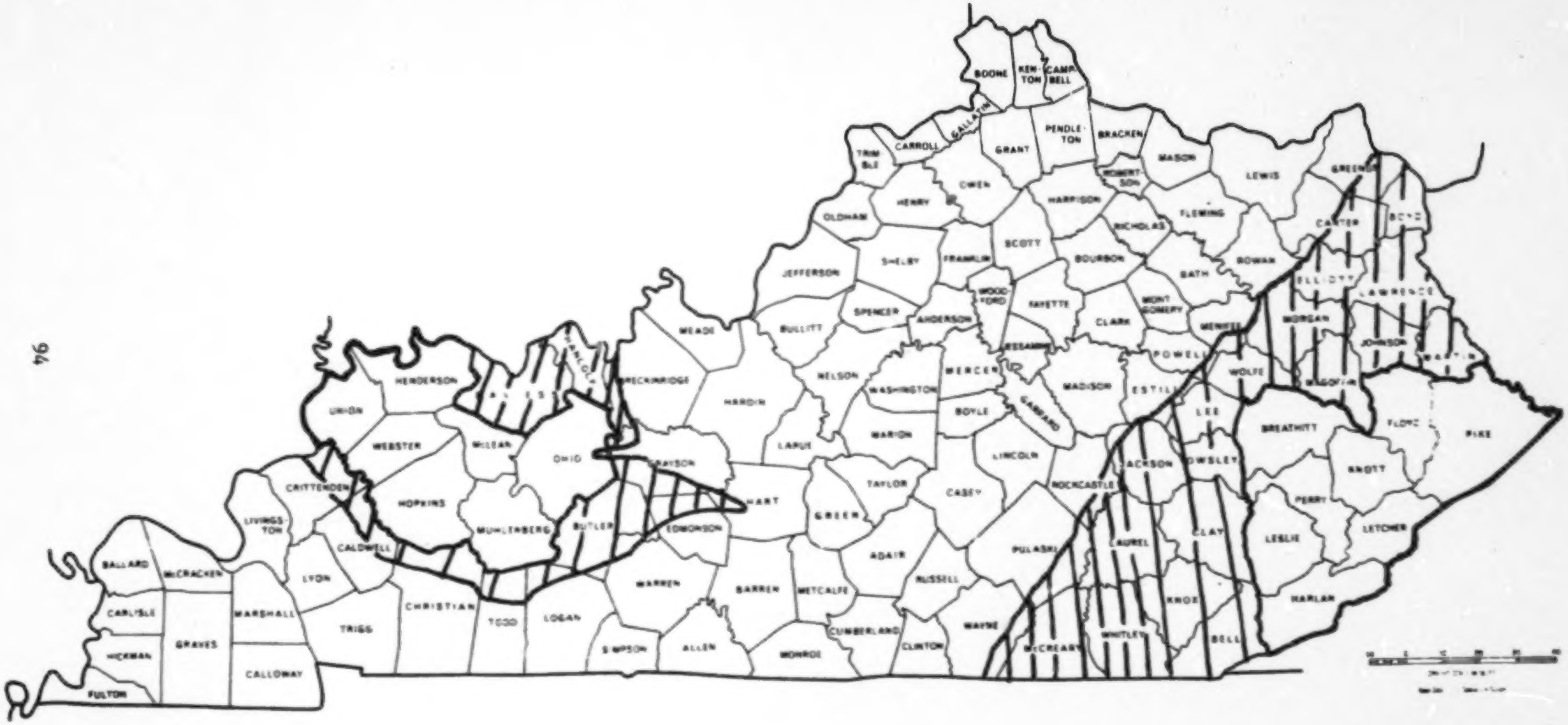

BASKETT
NEWMAN
WESTERN COAL FIELD
LEXINGTON
EASTERN
COAL FIELD
CATLETTSBURG

Figure 20. Kentucky Coal Liquefaction Projects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HARRISON
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FLEMING
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SCOTT
SHELBY
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BOURBON
BATH
ROWAN
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JEFFERSON
WOODFORD
FAYETTE
MONTGOMERY
MORGAN
SPENCER
ANDERSON
CLARK
MENIFEE
JOHNSON
MARTIN
BULLITT
MEADE
JESSAMINE
POWELL
WOLFE
MAGOFFIN
HANCOCK
NELSON
WASHINGTON
MERCER
MADISON
ESTILL
BRECKINRIDGE
HARDIN
BOYLE
GARRARD
LEE
BREATHITT
FLOYD
PIKE
HENDERSON
DAVIESS
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McLEAN
OHIO
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LARUE
MARION
LINCOLN
JACKSON
OWSLEY
KNOTT
CRITTENDEN
HOPKINS
TAYLOR
CASEY
ROCKCASTLE
PERRY
LETCHER
LIVINGSTON
MUHLENBERG
BUTLER
HART
GREEN
EDMONSON
ADAIR
PULASKI
LAUREL
CLAY
LESLIE
BALLARD
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CALDWELL
LYON
RUSSELL
KNOX
HARLAN
CARLISLE
MARSHALL
CHRISTIAN
TRIGG
WARREN
BARREN
METCALFE
TODD
LOGAN
CUMBERLAND
WAYNE
McCREARY
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BELL
HICKMAN
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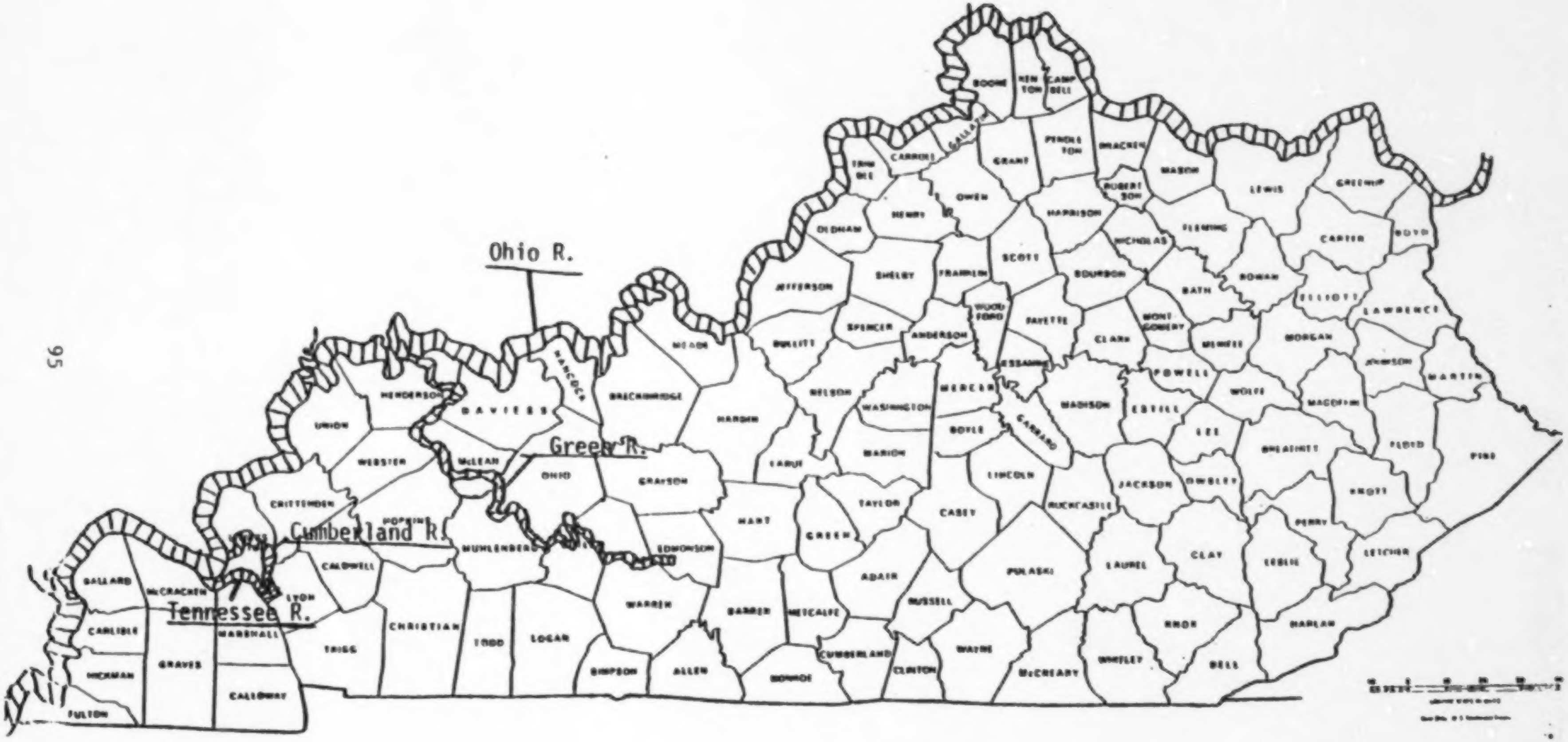
SIMPSON
ALLEN
MONROE
CLINTON
CALLOWAY
FULTON

Figure 21. Kentucky Coal Fields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GRANT
OWEN
HENRY
OLDHAM
MASON
ROBERTSON
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NICHOLAS
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FRANKLIN
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LAWRENCE
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WOODFORD
FAYETTE
SPENCER
ANDERSON
MONTGOMERY
CLARK
MENIFEE
MORGAN
JOHNSON
MARTIN
BULLITT
MEADE
HANCOCK
JESSAMINE
POWELL
WOLFE
MAGOFFIN
NELSON
WASHINGTON
MERCER
MADISON
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DAVIESS
BRECKINRIDGE
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PIKE
UNION
WEBSTER
McLEAN
OHIO
GRAYSON
LARUE
MARION
LINCOLN
JACKSON
OWSLEY
KNOTT
CRITTENDEN
HOPKINS
HART
TAYLOR
CASEY
ROCKCASTLE
PERRY
LETCHER
LIVINGSTON
MUHLENBERG
EDMONSON
GREEN
CALDWELL
LYON
PULASKI
LAUREL
CLAY
LESLIE
BALLARD
McCRACKEN
ADAIR
RUSSELL
CARLISLE
MARSHALL
CHRISTIAN
TODD
LOGAN
WARREN
BARREN
METCALFE
KNOX
HARLAN
HICKMAN
GRAVES
TRIGG
CUMBERLAND
WAYNE
WHITLEY
BELL
FULTON
CALLOWAY
SIMPSON
ALLEN
MONROE
CLINTON
McCREARY

Figure 22. Major Rivers of Kentucky

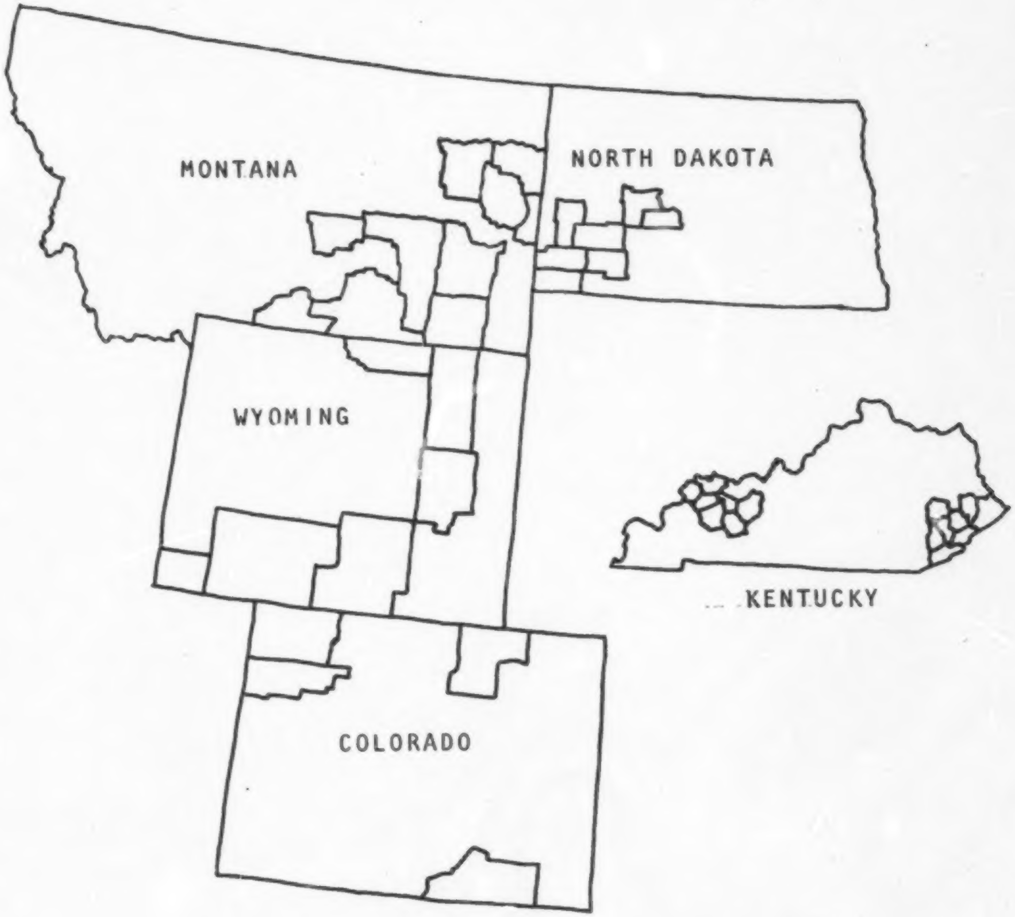
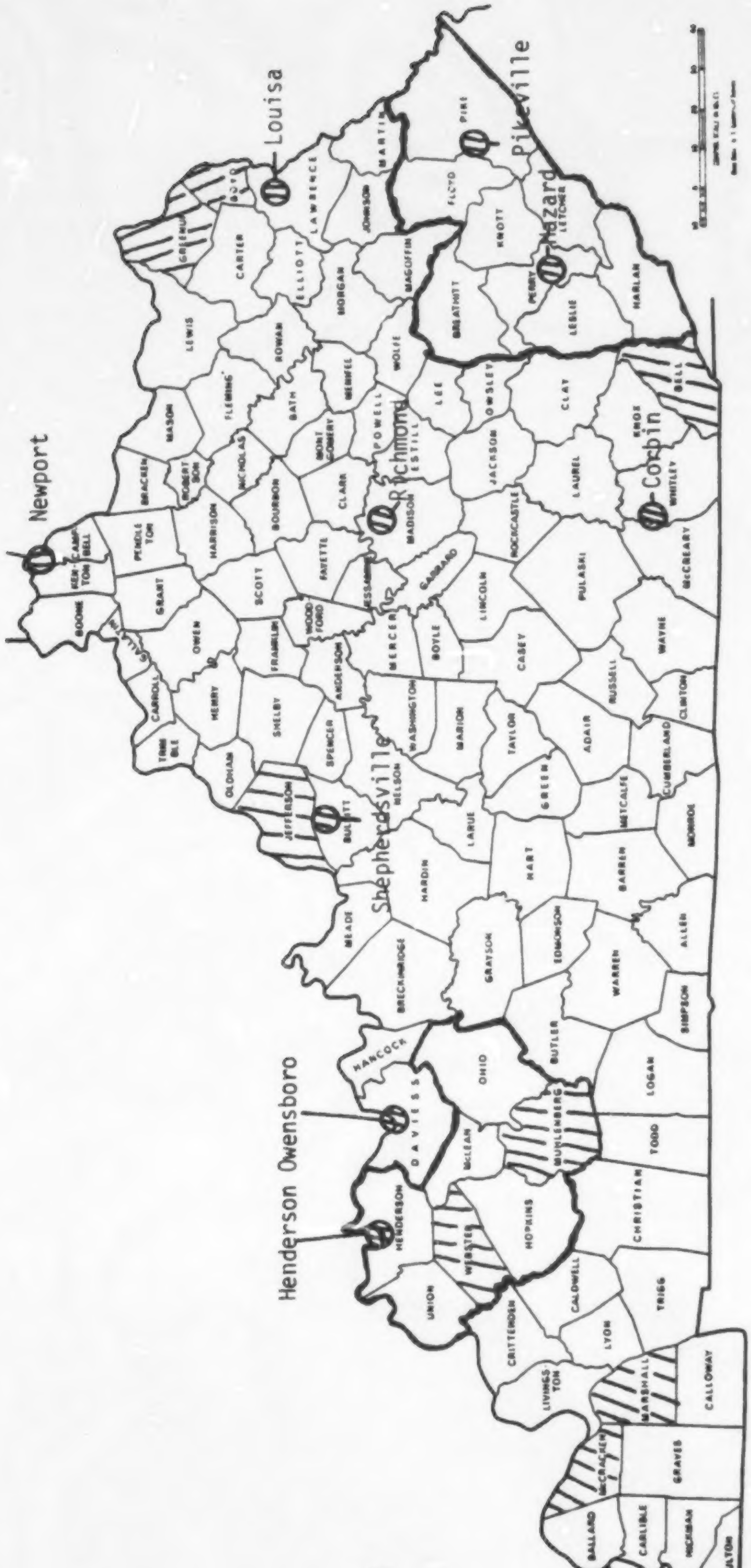

MONTANA
NORTH DAKOTA
WYOMING
KENTUCKY
COLORADO

Figure 23. Size of Some Counties in Western States, Compared With Kentucky's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Henderson
Owensboro
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BRACKEN
ROBERTSON
MASON
LEWIS
GREENUP
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ELLIOTT
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MARTIN
JOHNSON
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ROWAN
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OLDHAM
JEFFERSON
SHELBY
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FAYETTE
CLARK
MONTGOMERY
BATH
MENIFEE
POWELL
WOLFE
MAGOFFIN
FLOYD
PIKE
KNOTT
LETCHER
PERRY
BREATHITT
LESLIE
HARLAN
BELL
KNOX
CLAY
OWSLEY
LEE
ESTILL
MADISON
JESSAMINE
GARRARD
JACKSON
ROCKCASTLE
LAUREL
WHITLEY
McCREARY
PULASKI
LINCOLN
BOYLE
MERCER
ANDERSON
SPENCER
BULLITT
NELSON
WASHINGTON
MARION
CASEY
TAYLOR
GREEN
ADAIR
RUSSELL
WAYNE
CLINTON
CUMBERLAND
METCALFE
MONROE
LARUE
HARDIN
MEADE
BRECKINRIDGE
HART
BARREN
ALLEN
GRAYSON
EDMONSON
WARREN
SIMPSON
HANCOCK
DAVIESS
OHIO
BUTLER
LOGAN
McLEAN
MUHLENBERG
TODD
HENDERSON
WEBSTER
HOPKINS
CHRISTIAN
UNION
CRITTENDEN
CALDWELL
LYON
TRIGG
LIVINGSTON
MARSHALL
CALLOWAY
McCRACKEN
BALLARD
CARLISLE
GRAVES
HICKMAN
FULTON

Figure 24. Kentucky's Nonattainment Areas for SO_2 and TSP

TABLE 25. RESULTS OF SITING OPPORTUNITIES ANALYSIS

STATES	COUNTIES REMAINING AFTER SCREENING	300,000 BPD COUNTIES
MONTANA	10	4
WYOMING	6	5
COLORADO	3	1
NORTH DAKOTA	7	3
TEXAS	1	
WEST VIRGINIA	5	
PENNSYLVANIA	1	
ILLINOIS	8	
	41	13
TOTAL 6,700,000 BPD		

TABLE 26. SUMMARY OF SCREENING ANALYSIS

STATE	NUMBER OF COUNTIES	COUNTIES WITH ADEQUATE COAL RESOURCES	REMAINING AFTER NONATTAINMENT	REMAINING AFTER PSD CLASS 1	REMAINING AFTER WATER
MONTANA	57	16	13	10	10
WYOMING	23	7	7	6	6
COLORADO	63	7	7	3	3
UTAH	29	3	3	0	0
NEW MEXICO	32	2	0	0	0
ARIZONA	14	1	1	0	0
NORTH DAKOTA	53	12	12	7	7
TEXAS	254	1	1	1	1
OHIO	88	14	0	0	0
PENNSYLVANIA	67	16	1	1	1
WEST VIRGINIA	55	22	10	5	5
VIRGINIA	96	3	0	0	0
KENTUCKY	120	15	0	0	0
INDIANA	92	5	0	0	0
ILLINOIS	102	33	8	8	8
ALABAMA	67	2	0	0	0
	1212	159	63	41	41

TABLE 27. BASIS FOR EXCLUSION OF POTENTIAL SYNFUEL PLANTS IN KENTUCKY

	COUNTIES EXCLUDED
COAL RESOURCES	105
AIR QUALITY	15
	120

TABLE 28. COUNTY SIZE, WESTERN STATES VS. KENTUCKY

MONTANA (10) -	AVG. COUNTY	2625 SQ. MI.
COLORADO (3) -	AVG. COUNTY	1650 SQ. MI.
N. DAKOTA (7) -	AVG. COUNTY	1330 SQ. MI.
WYOMING (6) -	SWEETWATER	9460 SQ. MI.
	CARBON	7565 SQ. MI.
	CAMBELL	4740 SQ. MI.
	CONVERSE	4180 SQ. MI.
	SHERIDAN	2400 SQ. MI.
	UINTA	1910 SQ. MI.
	AVG. COUNTY	4080 SQ. MI.
KENTUCKY (0) -	PIKE	782 SQ. MI.
	MUHLENBERG	481 SQ. MI.
	HENDERSON	433 SQ. MI.
	AVG. COUNTY	337 SQ. MI.

TABLE 29. EMISSIONS FROM COAL-FIRED POWER PLANTS

10,000 TPD HIGH-SULFUR COAL - 1,000 MW ELECTRICITY
(3.5% SULFUR; 10% ASH; 12,000 Btu/lb)

PRE-STANDARDS

700 TPD SO_2

800 TPD PARTICULATES

1971 NEW SOURCE PERFORMANCE STANDARDS

144 TPD SO_2

12 TPD PARTICULATES

1978 NEW SOURCE PERFORMANCE STANDARDS

72 TPD SO_2

3.6 TPD PARTICULATES

TABLE 30. AMOUNTS OF SO_2 AND PARTICULATES FROM COAL-FIRED POWER PLANT VS. SYNCRUDE PROCESSES

SOURCE	SO_2 T/D PER 10,000	TSP T/D COAL
1. COAL-FIRED POWER PLANT		
PRESTANDARDS	700	800
1971 NSPS	144	12
1978 NSPS	72	3.6
2. H-COAL		
FUEL OIL:		
FUEL GAS	8.5	1.0
COAL	16.5	1.32
SYNCRUDE:		
FUEL GAS	8.8	1.0
COAL	20.6	1.47
3. HYGAS	20.5	2.1
4. COAL TO METHANOL TO GASOLINE	8.9	3.0
5. SRC I	0.46 - 0.59*	1.75

*INTERMITTENT EMISSIONS, AVERAGED OVER 1 YEAR.

TABLE 31. COAL TO METHANOL TO GASOLINE: EMISSIONS AFTER CONTROLS

Major Air Pollution Sources	Pollutant Emissions After Controls (Tons/Year)				
	SO_2	Particulate Matter	Nitrogen Oxides	Carbon Monoxide	Nonmethane Hydrocarbons
CO_2-Rich Rectisol Vent	310	---	---	24,090	---
H_2S-Rich Rectisol Vent	480	---	760	20	3
MeOH Stripper Vent Cond.	---	---	---	---	---
MeOH Conv. Regen. Off Gas	---	---	---	---	---
Startup/Regen. Heater	---	---	1,300	30	5
Alkylation Reboiler Furn.	---	---	220	5	1
Boiler Flue Gas	23,674	5,203	41,170	2,300	700
Coal Grinding/Drying	---	100	2,190	50	9
Lime Kilns	---	130	2,930	70	13
Petroleum Liquid Tanks	---	---	---	---	48
Sour Cond. Stripper	---	---	---	---	---
Wastewater Stripper	---	---	---	---	---
Cooling Towers	---	---	---	---	1,300
Flare	---	---	30	1	175
Total Emissions	24,464	5,433	48,600	26,566	2,254

Source: Badger Plants, 1979

tucky is not dealing directly with ORBES in the assessment of synthetic fuels facilities is quite simply that our assessment is concerned with base-loaded large coal-fired and nuclear-fueled electrical generating facilities. We are not directly assessing synthetic fuel facilities.

Mr. Princiotta: We are familiar with some of the Western states that are less than enthusiastic about the oil shale and liquefaction industries.

Are you reflecting the views solely of the State of Kentucky's Department of Energy, or are you integrating what you are saying with the concerns of the environmental department, which is usually a very strong department in Kentucky? If so, how do you explain your promotion of liquefaction, in contrast to many of your sister states who are less than enthusiastic about a major industry in their state?

Mr. Enoch: I don't think that's too hard to answer. We are very enthusiastic about attracting the synthetic fuel industry, as is our Department of Natural Resources. They are very tough and they are tough on us, but I think they want a synthetic fuel plant. They just want to make sure that they are built as cleanly as possible. I can't really find fault with that at all.

Yvonne Garbe, EPA: I am wondering if the state has developed cost data on those projects and/or any cost effects from the recently promulgated regulations from the Office of Surface Mining?

Mr. Enoch: I cannot answer the question about the Office of Surface Mining. I am not familiar with that at all.

As far as the cost of complying with RCRA, we haven't prepared any figures of our own, but we have looked at those of others. We think that this would be a very serious factor in the synthetic fuel industry, particularly in Kentucky.

It's going to be very expensive to dispose of these wastes in Kentucky if they are classified as hazardous. We are going to need several thousand acres to bury the large volume of wastes. It would be very difficult to secure a hazardous waste landfill that size.

That's even optimistically assuming that a site could be found for a hazardous waste disposal facility. Every indication is that this will be very tough to come by in Kentucky because, as you know, nobody wants hazardous waste around, even if it's a low degree of hazard. We are talking about something that is much larger than any hazardous waste facility that we have already.

Norbert Jaworski, EPA: Are you talking about changing the Kentucky Derby song to the synfuel song?

Mr. Enoch: We are already singing that song. Can't you hear us?

Dario Monti, DOE: Are you going to publish some of your work on siting in the next year? We are interested in following up on that.

Mr. Enoch: Yes, we will. We are working on several impact assessment studies and an integrated impact assessment. We are also trying to identify alternative sites, as I mentioned.

All three of these projects will be underway next year. I am not sure if I can say how long it will take to complete them.

Mr. Princiotta: Dario, do you want equal time to shout about that?

Mr. Monti: I want to be sure that people understand the ground rules and the circumstances under which this siting was done.

As a matter of fact, when I saw the results, I did go to my superior and said, "There is a zero after Kentucky and that's not going to go down very well." I wanted to look at the data. But in any event, the idea was to, in a very short span of time, make a quick check to see whether there is enough space in this country to handle the kinds of production the President was interested in.

It is not a siting analysis per se. We wanted to see if we could identify sufficient area to handle the load. Unfortunately, the way they plotted out the counties, Kentucky ended up with a zero.

Mr. Enoch: We at the Kentucky Department of Energy understood that. We understood the purpose of the DOE report. That didn't slow us up a bit. But there were people raising the devil with us about it.

So, I guess it was the method that DOE chose that stuck in peoples' minds. To see if they could achieve this goal, DOE tried to identify sites.

Mr. Monti: We tried to identify local sites by county segregations, that's all, they either passed certain criteria or they didn't. That was the end of it.

Fred Glaser, DOE: I can share with you one paragraph that Ruth Clusen, DOE Assistant Secretary for the Environment, presented to the House Science and Technology Committee on September 7, 1979, in response to inquiries on that report.

"I wish to add one final point about the report. Judging from the number of phone calls my office has been receiving, it appears that some people misunderstood the purpose of Part Three of the analysis. That chapter was not an analysis to determine specific sites and does not indicate where DOE thinks synthetic fuel plants should be located. Rather, it was an analysis to determine whether certain minimal capacities of a synfuel industry could be deployed. Some of the counties identified in our analysis as potential sites may actually present major obstacles to a plant that were not noted in the analysis. On the other hand, some counties excluded by the very conservative assumptions of the analysis could prove to be acceptable. On balance, the report is a reasonable first assessment, but it should not be considered precise at the county or even at the state level."

I have no idea what states she had in mind.

A quick question, though: Your plans, I guess, were twofold -- identify the Fischer-Tropsch interest and the H-Coal commercialization. There had been some discussion several months back about the coal-to-methanol project that was being sponsored by TVA, the State of Kentucky, and Badger. Is there any continued activity on this particular proposal?

Mr. Enoch: Kentucky has been working for a couple of years on what we call the chemical-energy park. It would combine coal gasification facilities with some base-load industrial users in an industrial park that could eventually grow to process other feedstocks.

We thought a good first shot would be indirect liquefaction to form methanol from syngas and we participated with TVA to study that. TVA has since dropped their role. They are no longer participating with us in the energy park. They have taken their gasification plans and gone to Alabama with them.

Kentucky is still pursuing this idea, but not as intensively as we were, owing to TVA's non-participation and also to the fact that Grace has now submitted a proposal to DOE to do a methanol synthesis plant.

Mr. Princiotta then introduced William Telliard of EPA's Effluent Guidelines Division.

Standard-Setting Procedures, Activities, and Plans Relating to Liquid Effluents from Coal Liquefaction: William Telliard, Effluent Guidelines Division, EPA.

At present, our division has met a number of times with Frank and most of the representatives from Cincinnati and RTP Laboratories to talk about programs to lead to the development of New Source Performance Standards for the synthetic fuel industries. So far, we have done nothing, which makes us quite harmless. We will, of course, have to draw upon the two laboratories for the data base to initiate our work-up.

EGD priorities are set by a different driving force than the Office of Research and Development's. Our priorities are those industries with the shortest schedule before coming on line, i.e., with an immediate need for an NPDES permit to operate. So, while R&D's drive is geared largely toward a national program, ours is kind of parochial in that we are going to look more at the installations that will be going commercial first.

In that light, we already met and discussed the efforts we want to initiate in gasohol and also, to a lesser extent, in gasification. Our data-gathering efforts vary somewhat from R&D's, in that we are going to address the 65 priority pollutant groups which somewhat fall in Group 1 and Group 2 of the assessment, but not completely.

The 129 that were originally reviewed under the present BAT Program would be addressed, but we are not going to restrict our studies to just the 129, but also all 65 categories, plus Paragraph C of the NRDC Consent Decree, which makes up another 12 to 14 organic groups.

We hope to conduct a joint data-gathering effort with R&D. As it looks right now, we hope to begin in 1980, to look at all of them in some degree or other. By the end of the year, we hope to have sufficiently clear ideas about priorities to be able to predict when the regulations could be on the street. At present, John Lum is projecting that it will be 1983 before we can issue proposed regulations for liquefaction. This is all predicated on the availability of money and people, which are two pretty good cornerstones. If we don't get either, we will probably do less.

The other approach that we are going to initiate lies in our data-gathering requirements, to generally "function under the 308 requirement of the law."

The reason we do this is that we have been burned in the past, either intentionally or unintentionally, when we have come out with regulations. Going the 308 route also makes life a little easier for both of us when we get down to splitting hairs in court.

In addition, we have a requirement that we can't write a regulation without doing an economic assessment -- an impact statement. This means that when we are done, we are going to have to supply a contractor with engineering costs for implementing an environmental control program for water in each of the processes. They are then going to have to sit down and look at the impact of these particular regulations on that industry: Will it prevent them from coming into existence? Will it change their location? Will it, in any way, inhibit the total program?

Economics used to be the tail that wagged the dog. Now, we have two dogs and they are equal in consideration.

The other big push that we would like to see -- and I don't care who does it -- is some treatability information. Again, we have talked to Cincinnati and RTP about it, but an early start in gathering it -- whether we do it or they do it or we do it jointly -- is something that we find is a benefit to all. If, for example, for some unknown reason, we didn't have a regulation out, it would help the folks who had to write the permit if they had the treatability information so that they could sit down and do something constructive. I think we are all aware of the fact that we have to have something done. I think the minimum that the permit writer can work with is treatability data. So, I think it's one of the priorities that we have to address in our program and I hope it will be a joint effort with R&D.

Mr. Princiotta: Let me encourage you to say a little more. Can you spend a little more time talking about how you actually write the guidelines that might impact on the liquefaction industry? I think some of the people here might not be aware of the process.

Mr. Telliard: One of our primary steps is waste characterization, both for traditional toxic pollutants and for any nonconventionals that would be a major constituent of the operation.

Once we have defined the waste characterization, we look at alternative treatment technologies that are available. These are all technology-based limitations; they are not related to health effects or water quality.

From there, we move to the economics and the engineering costing to develop the regulation.

So, it's basically four major areas. The cornerstone of the whole thing is waste characterization and waste treatability. Once you get that out of the way, costing is just a lot of time and money.

Sid Thomson, Fluor Corporation: You said you are not going to be setting effluent guidelines. How will people designing plants know what to design to?

Mr. Telliard: We are hoping to have a regulation out by 1983, although that may change.

Mr. Princiotta: May I help answer that? We hope pollution control guidelines documents will provide the guidance before they are superseded.

Mr. Thomson: You are saying that we will have to follow proposed guidelines until -- when do you expect the proposed outlines?

Mr. Telliard: Frank is saying that there is going to be a guidance manual. We intend to work with ORD on the guidance manual so it will support, as much as possible, our data base.

Mr. Princiotta: We are talking about roughly 1981 in getting those out.

Mr. Telliard: A guidance manual then will, we hope, turn into what we call a development document, which supports a regulation. We have some additional steps and hoops to jump through -- the economics, the costing, and so on.

The guidance document and the development document would both be based on that treatability information that we hope to generate someplace, somewhere. So if, for example, we didn't have a regulation out and you were building a plant, whoever was issuing you the permit would at least have the treatability information and the best engineering judgment of what you should put in.

Mr. Thomson: So, it really hasn't changed. Once we submit what we suggest is the treating process, they will review it, and decide at that time whether we are going to get a permit.

Mr. Princiotta: Why don't you explain how it relates to NPDES (National Pollutant Discharge Elimination System)? I think there is some confusion on that.

Mr. Telliard: Okay. The problem has been that there cannot be a new source without New Source Performance Standards. I don't know why we did that to ourselves, but we did. So, if you need a permit, the permit writer needs something to start with.

It would be easy if there were regulations; he would put down the regulation in the permit. If there is no regulation, he has to have something in the drawer that will help him. We hope it will be the treatability information combined with part of the guidance document, which Frank is now projecting will be ready in 1981.

Bruno Loran, Ralph M. Parsons Co.: How are you involved with the completion of the Multimedia Environmental Goals? How do you interface with those?

Mr. Telliard: Our only media is water. Since we are going to be out gathering data, say before the solid waste people are, we are proposing to gather additional data or at least samples for work-up in their programs. We are completely channeled in water.

Mr. Princiotta: Can I also respond to that? Bob Hangebrauck, I thought I heard you in conversation with Norb Jaworski yesterday on Multimedia Environmental Goals and how they are used in the research program to prioritize streams and pollutants.

We don't see any role for that system at the current time in the regulatory end of the business. We don't want to overplay that methodology. It's useful, but right now, it does not have a planned role in the guidance document or in the ultimate regulations.

Robert Hangebrauck, EPA: I might just add that related to the extent that they have eventually incorporated any regulations and standards that exist, so --

Mr. Princiotta: Where there is a regulation, that will be the goal.

Norbert Jaworski, EPA: When the water quality criteria documents are developed as part of the other division in the headquarters water program, the other 129 criteria then will be part of our target values. So, parallel to Telliard's work, there is another whole set of efforts going on involved in water quality criteria documents, which are only for 129 right now.

Mr. Telliard: The water quality criteria documents are ambient levels and they are all out, right?

Mr. Princiotta: I think they are close to it.

Mr. Telliard: They're all in draft form or proposed form right now.

Dr. Loran: The main reason why I brought up the subject is because the tax study issues in your intelligency program, all those books with the green cover, they all seem to apply the MEGs.

Mr. Princiotta: I just want to separate, though, the research function from the regulatory function. Those of you who are worried about regulations should not be worried about MEGs in any way, shape, or form.

James O'Hara, Ralph M. Parsons Co.: Having seen several of the planned schedules of several of the operating companies, I would appreciate your perspective on the extent to which your program will be facing action in the development of synfuels.

Mr. Telliard: We have set forth a timetable for consideration by our Assistant Administrator. It does not parallel ORD simply because we are looking at the ones who will need permits first. So, we are looking at gasohol and probably gasification prior to liquefaction, if we ever put them in order.

We're going to start all of them this year, but we hope that by the end of the year, we will have a priority set-up based on what you, the industry, tell us you see coming on the street.

Mr. Princiotta: Let me add to that, if I could. Even without the guidance documents, without the new source water standards, you still have permitting procedures, which we are going to hear more about from Terry Thoem in the next talk. I think the most important one, as I understand it, will be PSD and NPDES, the water permitting.

What we are saying is that we will, in the guidance documents, publish for all technology. We are not incompatible, by the way. We hope to have all guidance documents out during the calendar year 1981 or sooner, including alcohol, gasification, liquefaction, and oil shale processing.

We hope to get them out in 1981 or earlier so that we can help to guide permitting efforts and help tell the industry what EPA thinks, at this stage of the game, with an incomplete data base. This appears to be the right kind of control to incorporate in a new plan.

So, it's giving our current thinking to the developers and the permitters at federal, state, and local levels. Now, they will be superseded to some extent by New Source Performance Standards, which we have heard could come out in 1982 for the very new Btu gasifiers and probably later for the other plants. We are hearing now from Bill Telliard that in the liquefaction area, it will be perhaps 1983 before you might have the very first of those standards.

So, it's a continuum. I don't want to imply that without any of the necessary actions taking place, synfuel siting and permitting stops. It's not really the case. We think that this plan we have come up with will essentially provide some information when we get the guidance documents to the permitting officials and much more information when the legally binding regulations are proposed and promulgated in the early 1980s.

Dick Passman, DOE: Let's assume that the Energy Security Corporation is formed and there are a half dozen or ten companies that are willing to invest with whatever incentives are proposed. Will they know their costs or know that they will be able to estimate the costs of meeting your requirements or might you change them again later?

Mr. Princiotta: I can say that our goal would be to set those guidelines very close to the ultimate, legally binding regulations.

Quite frankly, as data are being generated, new information might call for a tighter -- or a less stringent, for that matter -- control approach. We can't make any guarantees.

Mr. Telliard: I think the other thing is too, that in permitting, since there won't be standards -- and Terry Thoem will probably touch on this -- the duration of a new source permit versus the standard NPDES permit is different. That's one of the reasons we like to have New Source Performance Standards, so you can get a new source permit, which, in theory, is two fives or whatever.

So, if you come in for a permit, unless there are New Source Performance Standards, you get an NSPS standard permit, which is only good for five years, and it will have to be renewed.

Mr. Passman: Is that five years after the plant begins operation?

Mr. Telliard: After the issuance of the permit.

Mr. Passman: It's not very useful.

Dale Denny, EPA: Are all the regulations, both air and water, to be renewed in air performance standards every four or five years to update?

Mr. Princiotta: Water every five years. Now, keep in mind, once you get a permit and, let's say, you are compatible with the current New Source Performance Standards for a new plant, you are not subject to any new, New Source Performance Standards in the area.

Jack Farmer, EPA: That's correct. If you started in with a plan, as far as air is concerned, and we did not have a New Source Performance Standard and you met the PSD requirements, you would not be subject to anything other than the PSD until we proposed a New Source Performance Standard. If you commenced construction after the proposal of the New Source Performance Standards, then you would be subject to that standard.

Mr. Princiotta: But obviously if you have an operating plant, you are off the hook as far as NSPS is concerned.

Terry is about to give us a real good story on this.

Mr. Passman: I am just worried about people being willing to commit.

We are talking about multi-billion dollar plants. There is a great deal of uncertainty. They want to finish their construction before a new standard comes out. They have a permit that is only good for five years from when they start detail design and here we are racing to get a million or million and a half barrels a day of liquid.

Mr. Princiotta: Jack, what is the life of an NSPS permit?

Mr. Farmer: It is in force for the life of the project.

Mr. Princiotta: So you're pretty well covered on air, I think. You get through PSD and you get your plant started before a new NSPS is proposed, except under the case where they change the ambient air quality -- let's say they change SIPs, State Implementation Plans -- you are pretty well free and clear.

Jack, is that right?

Mr. Farmer: From an air point of view.

Mr. Passman: What do you mean by starting construction? Is it breaking ground or do you have to get up some framework?

Mr. Farmer: I think Terry will probably cover all that.

Mr. Princiotta then introduced Terry Thoem of EPA's Energy Policy Coordination Office.

Permitting Procedures as They Relate to Coal Liquefaction Facilities: Terry Thoem, Energy Policy Coordination Office, EPA.

Talking about permitting and regulations is not a very popular issue with anyone these days, so I approach that with a little trepidation.

Before I get started, I want to tell a story: A vice president of one of the Colorado coal companies said he felt the federal government had a very unique approach to the solution of the energy crisis. He said that the Bureau of Land Management wouldn't let you lease any lands to develop coal. Even if you had a lease, the Office of Surface Mining wouldn't let you mine that coal. If you pass those two hoops, EPA probably wouldn't let you burn that coal.

That's a little bit of an overstatement, but the concept of over-regulation obviously is a very popular subject today.

EPA views itself in a shared partnership with the states as far as current environmental regulatory requirements are concerned. It's the intent of most of our legislation to delegate those programs to the states.

We have the legislation, of course, in the areas of air, water, solid waste, noise, radiation, and toxics. We don't have legislation, but we have interest and concerns in socioeconomic areas. But in many of those legislative areas, we do intend to delegate programs to the states.

I can only relate to you the experience in the Denver Regional Office. But in our six states, we have delegated NPDES to four of our states. We delegated the air quality programs to two of the six states. We probably will be delegating those programs to an additional two states in 1980.

Once we delegate a program to a state, we really assume more of an oversight role. The states will issue the permits, but if they need technical assistance on the issuance of that permit, they will come to us.

We also check the proposed issuance of that permit for consistency to make sure that, to the extent possible, Montana isn't using much more stringent requirements than, say Wyoming. We are trying to minimize duplication of efforts.

The Clean Air Act of 1977 requires that coal liquefaction developers comply with national ambient air quality standards that are enforced by the state through the State Implementation Plan. The main tool, however, for controlling air emissions is going to be the PSD, prevention of significant deterioration permit. A coal developer will have to come to either EPA or the state to get his PSD permit. That is a permit to construct and operate. It is slightly different from the NPDES permit.

So, before you break ground, before you commence any construction, you have to have a permit. As I mentioned, that permit is for the life of the project. Once you have that permit in hand, you are relatively off the hook.

There are two aspects to the PSD permit. The first is the concept of Best Available Control Technology (BACT). The coal liquefaction plant must put on air emission controls that the regulator, either EPA or the state, deems to be the Best Available Control Technology.

Mr. Princiotta: Relating just to criteria pollutants or to all pollutants? That's important.

Mr. Thoem: All regulated pollutants under the Act. There are some 14 pollutants that the Clean Air Act has identified. Best Available Control Technology must be employed for each one of those pollutants. We use the best data we have as guidance on what is BACT.

Obviously, we don't have a lot of coal liquefaction plants in operation, so we don't have a lot of source test data. The permitting people are going to rely heavily on the data that industry will submit. We have New Source Performance Standards established that we will use as a guide. We have some experience in permitting similar facilities, such as oil shale. We have gone a good ways toward the development of New Source Performance Standards for coal gasification plants. So, we have some guidance there that we can use in the issuance of that permit.

One of the aspects that we have to take into consideration in Best Availabile Control Technology is the cost of that control. When we decide what is BACT, we have to look at the cost effectiveness of that control technology, so we don't require something that is just out of sight from a control cost effectiveness standpoint.

The other portion of PSD, besides BACT, is the ambient increment. The nation has been divided up into Class One, Two, and Three areas. Most of the nation is Class Two, with special areas such as national parks and national wilderness areas being Class One. Those areas that are presently exceeding the national air quality standards are non-attainment areas and a different set of circumstances comes into play. PSD does not apply in non-attainment areas.

One thing I should also mention regarding the Clean Air Act is that we did issue PSD regulations. We were challenged in court. The court has made a recent decision in the Alabama Power case, which has put us in an area of uncertainty, especially in baseline monitoring. You have to have the PSD permit in hand before you can start construction. The Alabama Power case tended to say that you also have to have a year's worth of baseline monitoring before you can submit your PSD permit application.

So, in some cases, if you figure five years to construct that plant, you may be faced with having to submit a permit application six to seven years before that plant is operational. It's a long lead time.

The other component of the Clean Air Act that I should mention is a section that requires EPA to establish visibility regulations. Visibility protection is mandated in those special Class One areas -- national parks and wilderness areas. EPA is on a schedule to provide those proposed and promulgated regulations. We are days away from issuing a report to Congress that will give some guidance on what we are thinking. Proposed regulations will be out some time in mid-1980, with promulgated regulations perhaps in late 1980. Visibility regulations could have further constraints besides just meeting the Class One increments.

Let me turn your attention to water. The Clean Water Act has set forth a mechanism for surface discharge permits. We are issuing permits and will continue to do so in the absence of any effluent guidelines, as Bill Telliard mentioned. We have to. If you are going to have discharge, you have to have a permit. You have to apply for that permit 180 days before operation of the plant. So it's a much shorter time frame than the PSD permit.

Another water permit that may have to be obtained is required under Section 404 of the Clean Water Act. The Army Corps of Engineers has to issue a permit if you are going to disturb a navigable stream. EPA has a concurrent role in the issuance of that permit. A navigable stream is defined essentially as any flowing body of water. So, if there will be a disturbance in the stream, it will have to be authorized by permit.

We consider the issuance of the NPDES permit similar to the PSD permit concept, where we look at the technology base, but we also look at the stream standards. States have set stream standards and stream ambient water quality standards. We would first look at the proposed technology that is going to be applied to that discharge. If that satisfies the BACT concept, then we would further assure that the discharge of that stream would not violate any of those ambient water quality standards.

The other piece of legislation that we would have to deal with is TSCA, the Toxic Substances Control Act. There was a requirement for EPA to identify any chemical that had ever been introduced in a production commercial state. That list was published earlier this year.

There has been concern about whether synthetic fuels fall under the requirements of TSCA, the question being whether the products of a coal conversion plant are going to be different from any product that has ever been produced. If any are, you have to notify EPA 90 days before you begin to produce it. There could be requirements to do some testing for the carcinogenicity and mutagenicity of that product.

I don't know if there has been any regulation about the similarity of coal liquefaction products versus conventional oil-refined products. It has been argued that essentially the same type of stream will be used in refining as in boiler fuels. If there is not much difference, you won't have to go through this premarket notification.

Future permitting requirements could come in the form of the Resource Conservation and Recovery Act. Briefly, criteria have been proposed to differentiate between a hazardous waste and a solid waste. There are several different tests that could be performed to determine whether a material is a hazardous waste. If it's defined as a hazardous waste, then certain disposal standards will be promulgated for that type of waste.

The Safe Drinking Water Act also contains a tool for future permitting responsibilities, in the form of Underground Injection Control (UIC) regulations. If any of the liquids from the plant, such as wastewater, were going to be reinjected into the ground as a disposal technique rather than discharged on the surface, the UIC regulations would apply. You would have to get a permit. Again, the same sort of mechanism: EPA would not issue that permit if the program has been delegated to the state.

I might just share a couple of thoughts on what EPA is doing to provide some guidance to the industry. There has been discussion about the pollution control guidance documents and the environmental assessment reports. Those are going to provide some guidance. We will also look, in the interim, at similar industries and New Source Performance Standards or effluent guidelines that are applicable for those industries.

We do have that requirement to issue a permit and we are going to have to base it on something. We are doing everything we can to ease the pain of permitting. The Agency is looking at ways to consolidate permit requirements. EPA's Region VIII is trying to streamline the process of helping you get a permit. We have made a commitment to process all energy facility permit applications in six months, so you won't have a long, drawn-out wait for that permit.

I will just close on the comment that we certainly support Kentucky's thoughts that they would like to have some of those coal liquefaction plants.

Mr. Princiotta: Preferably in Kentucky.

Mr. Thoem: Preferably in Kentucky, as opposed to Montana, Wyoming, et cetera.

Bruno Loran, Ralph M. Parsons Co.: As it happens, I have two or three questions. First, should we qualify pollutants before control or as it's in the law now or should we qualify them only after control? Has any clearance been given to that?

Mr. Thoem: It's going to be controlled pollutants. We proposed some regulations in September and we have complied with what the Court said: It's controlled emissions rather than uncontrolled emissions. That really doesn't help coal liquefaction facilities or major facilities, but it does let a lot of small facilities off the hook.

Dr. Loran: The other question was about TSCA. My understanding was that the only compounds involved were new compounds and they were defined not as streamed but as chemical compounds. This is a separate entity.

Now, in coal liquefaction, you end up with a stream that may not have been produced before, but all the compounds in the stream have always been known in inorganic chemistry. I don't know how you can apply TSCA to that type of product.

Mr. Thoem: That's true, it does apply to the compounds. That's what I was trying to get at. There have been suggestions, at least by the oil shale people that the product shale oil is similar to all those compounds. They argue that the compounds are there in essentially the same concentrations as conventional crude oil; therefore, that's not a new product or a new compound and they don't have to go through the pre-market notification. The same argument could be used for coal liquefaction.

Dr. Loran: Would you accept the oil shale industry's point of view?

Mr. Thoem: That decision hasn't been made. There really hasn't been any forcing decision yet, because we don't have any oil shale facilities. I think right now we are leaning toward agreeing with that argument.

Mr. Princiotta: Excuse me, I wonder if you could qualify that, Terry. In the event that, let's say, somebody's coal liquids were covered under TSCA, I know one of the options under TSCA is that it will not allow construction on a project which obviously would not be attractive in this case. Are there other options, like industrial hygiene and general handling?

Mr. Thoem: Yes, there are two or three things that EPA can do. It can ban the production of that product, as we have for PVC, I believe. The other thing that we can do is set conditions on the manufacture, shipping, transportation, and usage of that product. So it could be a conditional sort of thing, getting at the industrial hygiene practices.

Mr. Princiotta: That does not necessarily mean that if you fall under TSCA, the liquefaction industry is dead?

Dr. Loran: I just want to know if you have to consider it or not.

Mr. Thoem: The important fact is that this list has been compiled, six volumes' worth.

Dr. Loran: They are all single products?

Mr. Thoem: Right. If those single products have been identified, then you don't have to go through the pre-market notification.

Dr. Loran: It's almost impossible, as you know. There may be 500 different compounds.

Mr. Thoem: I agree.

Dr. Loran: But anyway, my last question is one that was raised before. What is the definition of beginning construction? It seems to change from time to time.

Mr. Thoem: It's changed to some extent. Some of the legislation has changed the definition of commencing construction. Generally, it's defined as the breaking of ground, the site clearance, entering into a continuous, on-site construction mode, or the commitment of a significant portion of capital toward a project. That significant portion, in a few cases, has been defined as much as 10 percent of the project.

Dr. Loran: Is this also if it has been committed to design? For example, if 10 percent of their money was in the detail design, would that be considered a commitment?

Mr. Thoem: The cost would have to be 10 percent of the total capital cost, yes. Any design dollars would count toward that.

John Accardi, EPA: I have a question on NESHAP (National Emission Standards for Hazardous Air Pollutants). What is the possibility that some of the pollutants emitted from a coal liquefaction facility would fall under the NESHAP standards?

Mr. Thoem: I don't believe that the Hazardous Air Pollutants Standards, per se, would apply to the industry. For those people who are not familiar with it, we have things like mercury and beryllium, so we would look at those through the PSD permits.

Because of the Alabama Power case, we have to insure the Best Available Control Technology is employed for those pollutants but -- and Jack probably wants to add something -- the Hazardous Air Pollutant Standards for mercury are only applicable, as I recall, to specific industries, is that right?

Jack Farmer, EPA: Yes, that is right. Before we set a Hazardous Pollutant Standard, we have to determine that a particular compound, like mercury or beryllium or benzene, is considered a hazardous pollutant. Once they determine it's hazardous, we put it on the list of hazardous pollutants. Then we identify the sources of that pollutant, which we want to regulate. We are now in the process of developing standards for coke oven emissions.

If we conclude that some of these plants have carcinogens in their emissions, then they might, at that point, determine this should be under the regulations of the Hazardous Pollutants Act. That's a long way off. I don't think we are near -- and we are not even close to the NSPS right now.

Mr. Princiotta: Take a group like benzene that does fall under NESHAP. If you have not identified coal gasification, the source, can that be done pretty quickly?

Mr. Farmer: Probably, we will take that into account. We have probable New Source Performance Standards. Since it's an emerging industry, our New Source Performance Standards, theoretically, should pick up all plants.

It's not as if you have pollutants out there right now and you have to worry about picking up the existing sources. So, as we develop the New Source Performance Standards, we will be looking at all compounds. We hope that the technology that we will be requiring will control benzene or the carcinogens or whatever. It won't be necessary to put out anything under NESHAP.

James O'Hara, Ralph M. Parsons Co.: Could we return to one of the options that you mentioned when it is concluded that you should direct specific handling of a liquid? How would you proceed to define those handling procedures? What data base would you have and what would be the time frame to define those procedures?

Mr. Thoem: TSCA is so new, I don't think that we have really gone through that thought process yet. Of course, you would like to have some operating facilities on which to create a data base and you don't have any of those, so it would be difficult. I can't really given you a good answer.

Mr. O'Hara: What occurs to me is that perhaps one looks at the Food and Drug Administration's procedures. Those can be quite time consuming in terms of determining health effects.

To me, it's an important point, looking again at the schedules as to how that would be. How would you respond to that?

Mr. Thoem: I think we would probably, again, look at the similarity of that stream against any other type of stream and see what practices have been employed. I am expecting that the streams for coal liquefaction plants are not going to be that much different from what the industry is dealing with now.

Mr. Princiotta: Unfortunately, I think there is some evidence that they are quite a bit worse in terms of mutagenicity and carcinogenicity. I think oil shale is also going to fit into that category. We will have to chat about that.

I would like to get some opinions from the audience about the guidance documents that we have been talking about, perhaps including some product handling information and some discussion of best available handling procedures and industrial hygiene procedures, that could conceivably have regulatory interest.

Dr. Loran: I think it would be a good idea. Usually, ignorance is the worst thing. You have all these environmental groups who don't really know what's involved. If you come up with something written from EPA, which is a neutral source, I'm sure it will help clear the air.

Mr. Princiotta: There is, I think, a tendency, particularly with carcinogens, for people to think right away, there is no solution, the problem is infinite, the world will come to an end. If we can perhaps document some of the procedures, that might minimize the problem. We will consider that.

Norbert Jaworski, EPA: I would like to comment on your comment about EPA being a neutral source.

Mr. Thomson: You previously proposed regulations on coal gasification and they have evidently been shelved. Are they going to be used as a basis for your guidance document?

Mr. Thoem: It didn't go to proposed regulations. We issued a guidance series-type document that could have served as the basis for a proposed New Source Performance Standard.

The answer to your question is yes, we will use those types of documents, too, in the review of a PSD permit application. For instance, we look at what was identified as Best Available Control Technology for that source.

Mr. Princiotta: From a pollution control guidance point of view, yes, that's important. You may recall in the synthetic natural gas plants, they really only focused on sulfur and hydrocarbons.

Mr. Princiotta then introduced Richard Eccles of Hydrocarbon Research, Inc.

Hydrocarbon Research Plans in the Area of Coal Liquefaction: Richard Eccles, Hydrocarbon Research, Inc.

The other speakers at this forum are either from government, a major operating company, or a major engineering contractor. Then there's HRI. We have about 250 people and some pretty interesting technology that really fits into synthetic fuels. I guess that's why we are here today.

We are not an operating firm that commercializes plants or technology. We develop the technology and provide the service of making it available, including all of the front-end activities, such as laboratory work, planning, and early design work, that leads to getting a project off the ground, using our technology.

Here in Table 32 is a summary of what we have at HRI. In terms of H-Coal: the pilot plant operation at Catlettsburg and associated R&D at Lawrenceville, New Jersey. We have a 3.5 ton-a-day process development unit that has been used to simulate and confirm the operation that is designed for the Catlettsburg large pilot plant.

We are also working with Ashland, as you heard earlier, on their commercial plant activities. They are currently discussing contract bases for a phase zero design study for an H-course, DOE. The large pilot plant will be coming on-stream shortly.

Figure 25 shows the ebullated bed reactor that has 27 unit-years of commercial experience in oil service in three refining locations. It is adapted to the coal liquefaction operation simply by adding ground coal to the oil feed to the unit.

The feed to this reactor is upflow through the bed. The liquid's velocity is sufficient to expand the catalyst bed into the reactor such that the catalyst is then in random motion and the bed operates isothermally. The liquid phase then in the reactor is a continuous phase, in which the reaction takes place. We use the generic term liquid-phase hydrogenation to cover all the processes that I am describing here.

The bed is maintained in this expanded state by the operation of an ebullating pump at the bottom of the reactor. The pump can either be mounted in the base of the reactor or externally.

The products, gas and liquid, go into an external separator for separation. The vapor and liquid streams are handled in separate trains downstream. There is a recycle of heavy liquids which, along with fresh coal feed, makes up the total slurry feed to the system.

Catalysts can be added and withdrawn. The catalyst inlet is shown at the top and the catalyst outlet at the bottom. By being able to add and withdraw catalysts, we are able to sustain a constant catalyst activity throughout the whole bed and throughout the entire length of the run. This gives us one chemistry that is operative at all times and does not give us the problem of handling end-of-run conditions that are different, as, for example, in fixed-bed operations.

I will touch on some of the further advantages of the ebullated bed reactor. To begin with, it operates isothermally. Because of the expanded nature of the bed, there is a low and constant reactor pressure drop. We are adding and withdrawing catalysts, which in addition to providing the same yield structure and chemistry, also assures constant product quality at all times from the reactor.

This is a catalytic process with perhaps more operating variables than any other similar processing system. For example, the catalyst replacement rate is an independent variable that can be changed at will after the unit is designed and operating, in order to change the product slate, the product quality, or the yields.

Another advantage of applying this technology to coal liquefaction is that with the 27 unit-years of commercial experience in oil service and with something close to a one-to-one Coal commercial plant. We are also doing commercial plant studies for overseas concerns.

We are providing something close to a duplicate of our process development unit to be built at the Wilsonville SRC facility. This will permit an operation called by some "SRC-1/2", which is a process involving a short residence time, dissolving followed by solid separation, followed by H-Oil . We are under contract to provide a 100 barrel-a-day unit so that those operations can be studied at Wilsonville. Associated R&D work and commercial and plant studies are being performed at the R&D Center at Lawrenceville.

The Illinois Coal Gasification Group is developing one of the two DOE second-generation gasification projects. It's through the process design phase. That unit, if it goes ahead, will have a 2,000 barrel-a-day H-Oil unit handling the pyrolysis oil. There are, once again, laboratory and engineering studies and commercial plant studies going on. HRI is also working on a process that is a combination of our H-Coal and our H-Oil processes called COIL™, which stands for Coal/Oil Integrated Liquefaction. It's simply an ebullated bed with coal and residual oil fed as a mixture.

I would like to give you some background on the H-Coal process (Table 33). H-Coal is a patented catalytic hydroliquefaction process developed by HRI. It differs in certain important respects from the other two major direct hydroliquefaction processes that are being developed concurrently.

It's different in that it has the catalyst present in the reactor. The reactor is operated as an ebullated bed, and there is direct contact between the coal and the catalyst. There is, therefore, no reliance on the catalytic properties of the coal and no reliance on an external hydrogenation reaction system.

H-Coal has been under development for 15 years, with over 54,000 hours of operation in various bench and process development units and on a total of 14 different coals. We have been able to process successfully all of the 14 coals and do not see any particular problems with any coals that we know about. We have conducted extensive bench-scale operations in optimizing the process, evaluating new catalysts, and looking at those several coals. Also in the PDU, we have operated to confirm the design basis for the large pilot plant and have had successful operations on Illinois, Kentucky, and Wyodak coals.

The H-Coal development was initially funded by Dynalectron, HRI's parent company. At present, as identified earlier, our sponsors are four oil companies, the State of Kentucky, the Electric Power Research Institute, and, of scale-up from the commercial H-Oil reactor to the anticipated H-Coal reactor, the scale-up required and the degree of technical uncertainty on scale-up have been considerably reduced.

Figure 26 is a flow plan for one depiction of how the reactor can be set in place in the H-Coal plant. It shows the reactor and separator as seen in the previous figure. Solids reduction devices such as hydroclones can be used in order to tailor the right kind of recycle to return to the reactor. In this depiction, the fractionator bottoms material gas to partial oxidation to make up hydrogen. In addition, we are recovering hydrogen for recycle and sending out our distillable liquid products.

There are two modes of operation that will be tried in the large pilot plant at Catlettsburg: the syncrude mode and the boiler fuel mode.

The syncrude mode is of particular interest to us because operating with No. 6 Illinois coal, we are able to achieve yields in the range of 45 to 50 weight percent of liquids. These liquids have a particular yield distribution that distinguishes this process from its competitors. There is relatively little light material, C_4 and lighter, and relatively little 750°F-plus material in this liquid product. This is essentially a naphtha and a middle distillate.

I think we are going to see applications for all of these processes, each one of which makes its own particular product slate. Just looking at these processes as advertised at this point, and assuming no surprises in the development pattern of any of these, the product slates all appear different. Perhaps there will be a fit for many of these in the various markets anticipated. The petroleum refining business is certainly an analog of coal liquefaction; we can look at the proliferation of different kinds of process units that have been used effectively in the many different refinery configurations that we see around the world.

Table 34 describes the large pilot plant in Kentucky. I think the things that are different here are the objectives. It is not necessary, we feel, to demonstrate the process in all of its particular possible manifestations in the pilot plant.

We have definite objectives for this operation, which include demonstrating the chemical operability of the equipment and providing products for commercial testing. We need to verify yields, that is to say, quantify scale-up by comparing these yields with those from a smaller operation. Engineering data required for the plant design will be obtained, including data on appropriate materials of construction. Some perception will then come out of the operation as to how long the various critical equipment components can be expected to last in a commercial plant.

The operation is planned to go on for two years on three different coals, including the Wyodak coal. Wyodak coal has proved either to contain the wrong material or to lack the right material for some of the other processes, but it's been operating successfully at our Lawrenceville Laboratory at the 3.5 ton-a-day scale. We are confident that we will be able to demonstrate basically the operation of all the coals of interest in the Catlettsburg unit.

Table 35 is a brief outline of the Phase Zero Ashland Commercial Plant Design Proposal at this point, which will prepare for Phases 1, 2, and 3 of the commercial plant project.

I outlined earlier the several HRI projects in this area, one of which is the Wilsonville project to build an H-Oil unit for SRC upgrading (Figure 27). This is what is called SRC-1/2. It has basically a short residence time and then de-ashing, using a particular process of LPH, liquid phase hydrogenation. That's what we mean by H-Oil in this case. The basic objective here is to stake out this process at this particular size level.

What we are doing in our project is providing the process design for the ebullated bed unit plus detailed design and procurement of major equipment. We will be providing startup and operations assistance. We are running the smaller units back in the laboratory to predict and confirm some of these operations.

This work is being funded by the Electric Power Research Institute and we expect to start up next year.

Table 36 outlines the Illinois Coal Gasification Group's COGAS project. We have licensed a 2,000 ton-a-day H-Oil unit that will go into this project, assuming it goes ahead as a DOE-funded 2,000 ton-a-day operation on Illinois coal. The engineering on this H-Oil unit was done at HRI. The work was based on a successful bench-scale pilot work at our R&D Center.

The reason this ebullated-bed H-Oil process is interesting is that the H-Oil unit is particularly well suited to handle the solids that are found in the pyrolysis oils that we will find coming out as a by-product of many of the pyrolysis projects that are being contemplated. They have a pronounced tendency to foul preheaters and we're able to operate without need for preheaters because we can take advantage of the high degree of exotherm. With the isothermal reactor, this can be designed and operated very successfully and reliably.

The amount of hydrogen consumption for the operation as currently planned would be in the range of 1,500 to 2,500 standard cubic feet per barrel. That may sound like a lot until you consider what we are doing in direct coal liquefaction, which is adding 5,500 to 6,000 cubic feet per barrel of liquid produced.

Here it's a more modest amount, and it's keyed into a particular strategy on products. The bottom 10 percent would be directed back with the solids as recycle to the gasifier. There is a small amount of naphtha here, while the bulk of the product looks very attractive as a turbine fuel. It looks particularly attractive if the particular Pratt and Whitney work that was described earlier, called Burn Quick Clean, is used to handle the hydrogen. This would be a natural fit, we feel.

With the figures that the gentleman from Gulf showed us on the projections of electric power distribution versus time, I think we saw a lot of opportunities for combustion turbines. We think this is a natural marriage of coal pyrolysis, which yields pyrolysis oil as a low-cost coproduct, and this kind of ebullated bed technology featuring turbine fuel as the principal product for use in the electric power business.

We are going to do some additional work to expand the types of coal and the different kinds of operations that could be conducted with other liquids available from COGAS.

Table 37 briefly outlines the COIL^{TM} process. I have described both H-Oil, the ebullated bed process for oil, and H-Coal. This one combines the two.

If you recall, one of the earlier presentations projected that coal conversion will provide 2.5 million barrels a day of additional oil by 1990 or 1995, including 1.2 million barrels a day of coal liquid. That figure included 0.5 million barrels a day of heavy oil in 1990. We believe that the application of the ebullated bed process to heavy oil, plus the processing of refinery residual, will provide substantial opportunities. We also believe there will be many H-Oil applications in refineries.

As industry moves to displace oil with coal in large steam- and power-producing operations, we will see coal supply systems extending to the Gulf Coast and other parts of the refining world.

With coal systems linked to refineries and ebullated bed oil units, it's easy to see that one of the most likely uses of coal liquefaction would be to add coal to these ebullated bed units and to practice the COIL process.

Figure 28 simply shows the operation with coal together with oil from the refinery, coming through the heater into the reactor, with partial oxidation of the bottoms. We are anticipating that process will have an interesting future.

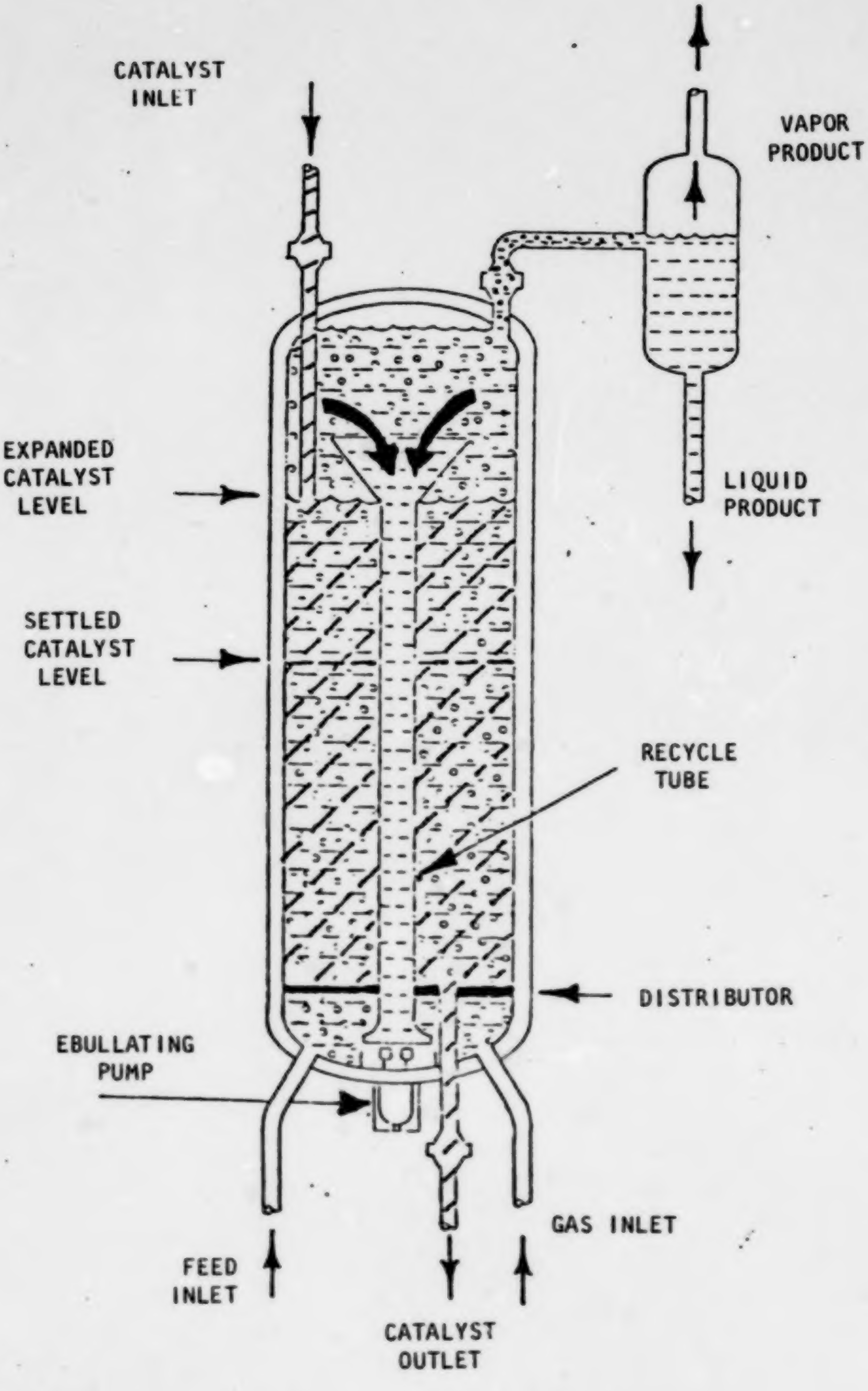

CATALYST INLET
VAPOR PRODUCT
EXPANDED CATALYST LEVEL
LIQUID PRODUCT
SETTLED CATALYST LEVEL
RECYCLE TUBE
DISTRIBUTOR
EBULLATING PUMP
GAS INLET
FEED INLET
CATALYST OUTLET

Figure 25. Ebullated Bed Reactor

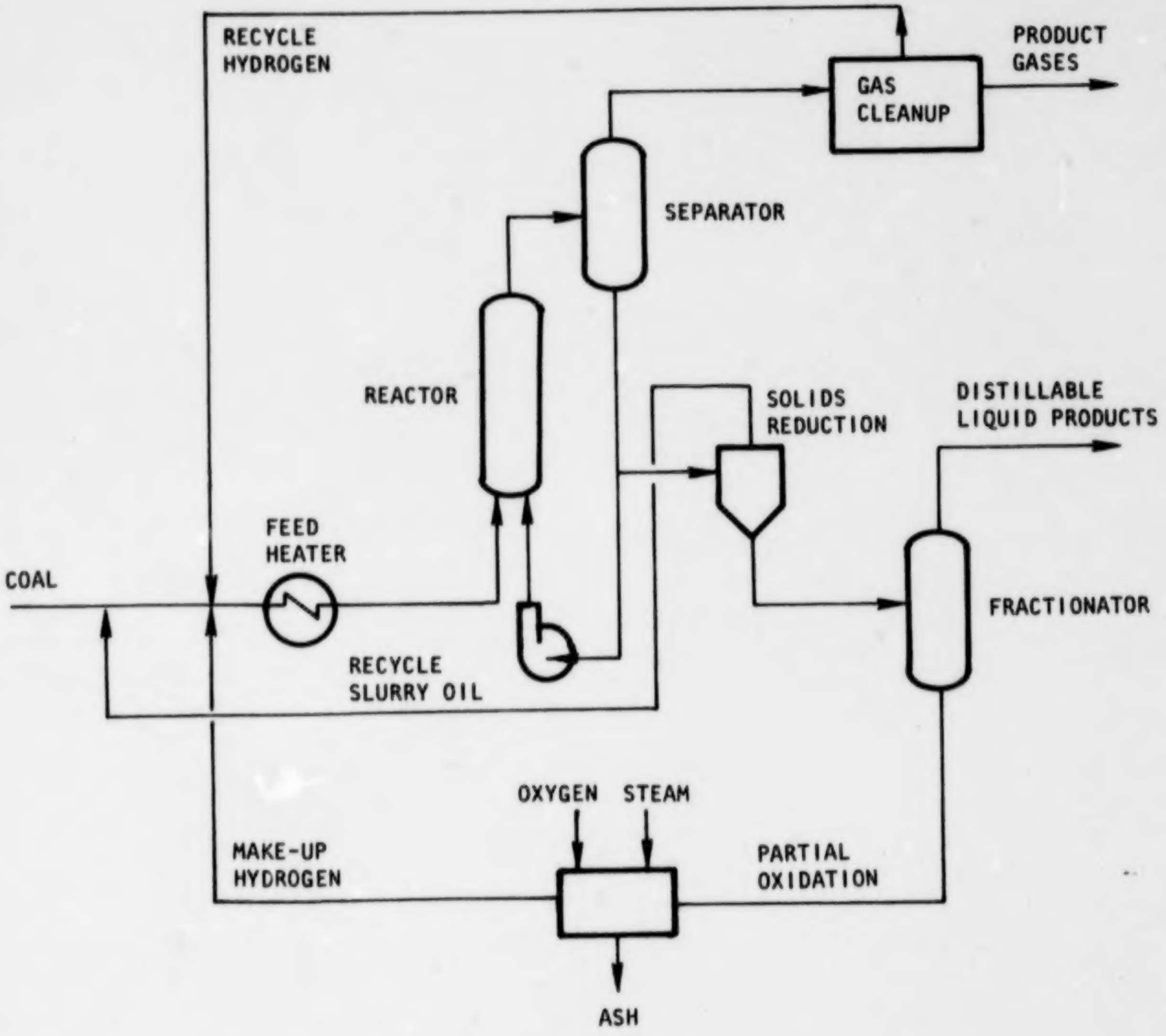
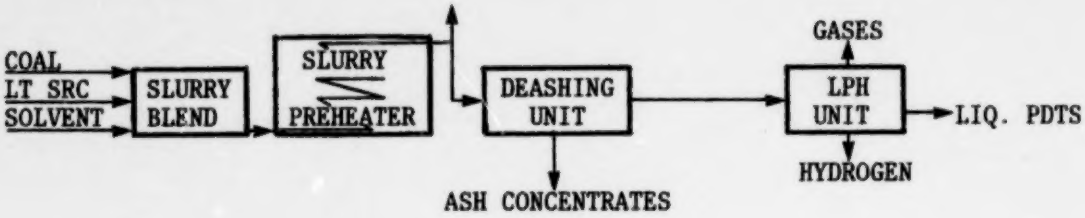

RECYCLE
HYDROGEN
PRODUCT
GASES
GAS
CLEANUP
SEPARATOR
REACTOR
SOLIDS
REDUCTION
DISTILLABLE
LIQUID PRODUCTS
FEED
HEATER
COAL
FRACTIONATOR
RECYCLE
SLURRY OIL
OXYGEN
STEAM
MAKE-UP
HYDROGEN
PARTIAL
OXIDATION
ASH

Figure 26. H-Coal Process

WILSONVILLE PROJECT

OBJECTIVE: PROCESS SRC/SOLVENT MIXTURES OF VARYING COMPOSITION AT VARYING SEVERITIES


COAL
LT SRC
SOLVENT
SLURRY BLEND
SLURRY PREHEATER
DEASHING UNIT
ASH CONCENTRATES
GASES
LPH UNIT
HYDROGEN
LIQ. PDTS

WORK SCOPE

- PROCESS DESIGN OF EBULLATED BED UNIT PLUS DETAILED DESIGN AND PROCUREMENT OF ALL MAJOR EQUIPMENT
- START-UP AND OPERATIONS ASSISTANCE
- DESIGN BASIS VERIFICATION THROUGH BENCH SCALE UNIT OPERATIONS

FUNDED BY

- EPRI

START UP

- SUMMER 1980

Figure 27. SRC Upgrading

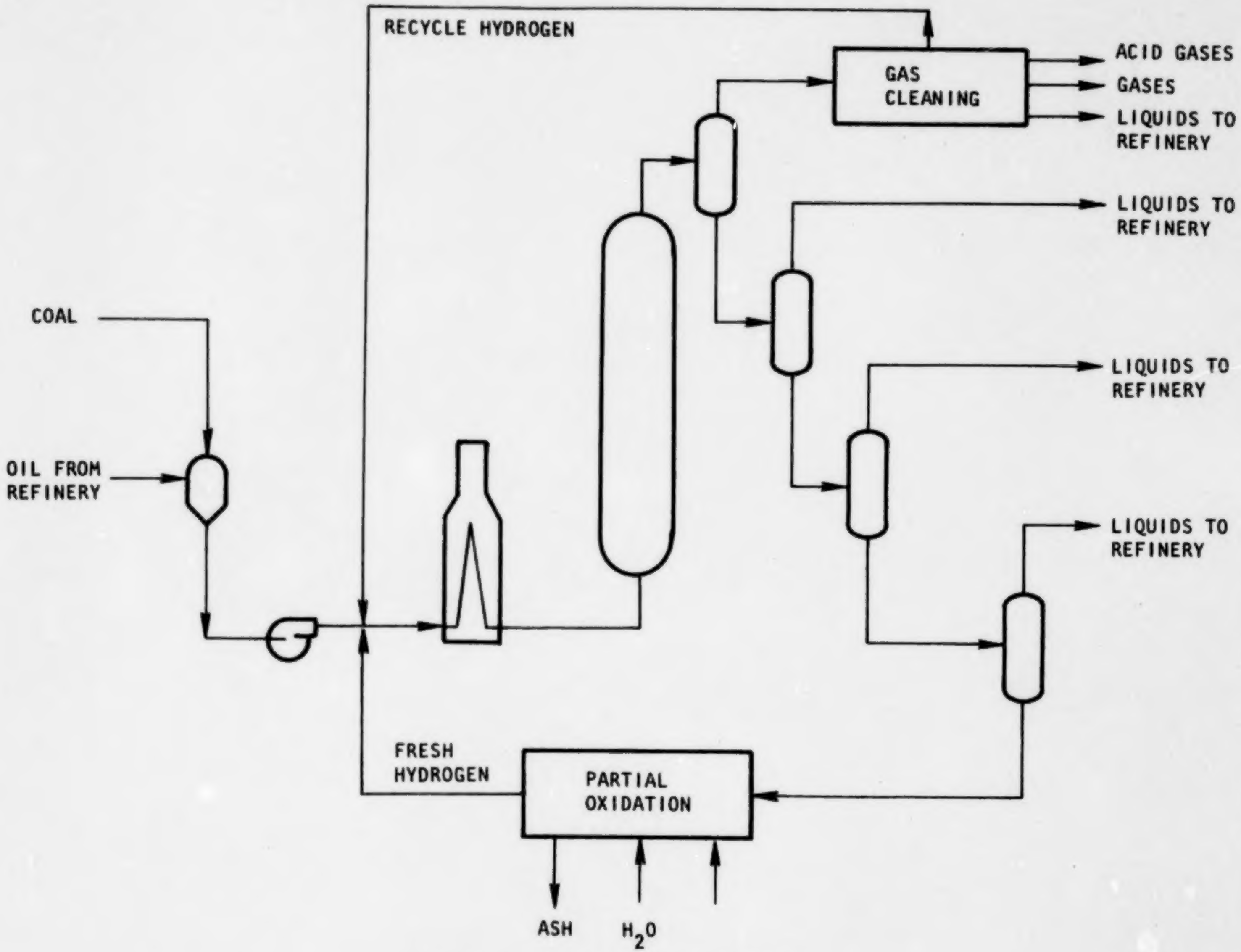

RECYCLE HYDROGEN
GAS CLEANING
ACID GASES
GASES
LIQUIDS TO REFINERY
LIQUIDS TO REFINERY
LIQUIDS TO REFINERY
LIQUIDS TO REFINERY
COAL
OIL FROM REFINERY
FRESH HYDROGEN
PARTIAL OXIDATION
ASH
H_2O

Figure 28. COIL Process Schematic

TABLE 32. STATUS OF HRI COAL LIQUEFACTION ACTIVITIES

H-COAL®

- PILOT PLANT OPERATION AT CATLETTSBURG
- ASSOCIATED R&D AT LAWRENCEVILLE
- PHASE ZERO ASHLAND COMMERCIAL PLANT DESIGN
- COMMERCIAL PLANT STUDIES

SRC UPGRADING

- WILSONVILLE UNIT
- ASSOCIATED R&D AT LAWRENCEVILLE
- COMMERCIAL PLANT STUDIES

PYROLYSIS OIL UPGRADING

- ICGG 2000 B/D UNIT
- ASSOCIATED R&D AT LAWRENCEVILLE
- COMMERCIAL PLANT STUDIES

COIL™

- COMMERCIAL PLANT STUDIES

TABLE 33. BACKGROUND OF THE H-COAL PROCESS

- H-COAL® IS A PATENTED CATALYTIC HYDROLIQUEFACTION PROCESS DEVELOPED BY HRI
- THE PROCESS PRODUCES C_4-975°F DISTILLATES IN THE RANGE OF 40-50 W % OF FEED COAL
- MORE THAN 15 YEARS OF DEVELOPMENT
- OVER 54,000 HOURS OF OPERATION IN
  - BENCH-SCALE AND PROCESS DEVELOPMENT UNITS
- BENCH-SCALE OPERATIONS
  - PROCESS OPTIMIZATION
  - CATALYST EVALUATION
  - NEW COAL EVALUATION
- PDU OPERATIONS
  - CONFIRM DESIGN BASIS
- FUNDING
  - INITIAL - DYNALECTRON, HRI'S PARENT COMPANY
  - PRESENT - DOE, EPRI, ASHLAND OIL, STANDARD OIL OF INDIANA, CONOCO COAL DEV. COMPANY, MOBIL & THE COMMONWEALTH OF KENTUCKY
- THE FEASIBILITY OF THIS PROCESS WILL BE DEMONSTRATED IN A 600 T/D PILOT PLANT IN CATLETTSBURG, KENTUCKY

TABLE 34. CATLETTSBURG PILOT PLANT

DESIGNED CAPACITY 600 T/D OF COAL

COMPLETION - LATE 1979

OBJECTIVES:

- DEMONSTRATION OF THE MECHANICAL OPERABILITY OF THE EQUIPMENT
- PROVISION OF PRODUCTS FOR COMMERCIAL TESTING AT RATES OF 100 TO 300 TONS PER DAY
- VERIFICATION OF YIELDS IN COMMERCIAL SIZE EQUIPMENT
- COLLECTION OF SCALE-UP AND ENGINEERING DATA
- SELECTION OF APPROPRIATE MATERIALS OF CONSTRUCTION
- ESTABLISHMENT OF MAINTENANCE REQUIREMENTS FOR KEY ITEMS OF EQUIPMENT

PROGRAM LENGTH - 2 YEARS

MODES OF OPERATION:

- SYNCRUDE (KENTUCKY 11, ILLINOIS NO. 6)
- BOILER FUEL (WYODAK)

TABLE 35. PHASE ZERO ASHLAND COMMERCIAL PILOT PLANT DESIGN

OBJECTIVE

- PLAN, DESIGN, ENGINEER, COST ESTIMATE, AND EVALUATE COAL LIQUEFACTION PLANT USING THE H-COAL PROCESS

COMMERCIAL PLANT DESIGN

- 25,000 T/D OF RUN-OF-MINE COAL
- 50,000 B/D OF HYDROGEN LIQUID PRODUCTS

TASKS

- PLANT DESIGN AND COST ESTIMATES
- ENVIRONMENTAL ANALYSIS
- PLANT SITE ASSESSMENT
- LONG-LEAD PROCUREMENT SPECIFICATIONS
- MARKET ANALYSIS
- ECONOMIC EVALUATION
- PROJECT MANAGEMENT
- PLANNING AND COST ESTIMATES FOR PHASES I, II, AND III
- FINANCIAL PLAN

TABLE 36. H-OIL® UPGRADING OF PYROLYSIS OIL

- HRI HAS LICENSED A 2000-B/D H-OIL UNIT FOR THE ILLINOIS COAL GASIFICATION GROUPS'S COGAS PROJECT
  - U.S. DOE IS SPONSORING PROJECT THROUGH DETAILED ENGINEERING (AT HRI)
  - BASED ON SUCCESSFUL PILOT PLANT RUN AT HRI'S R&D CENTER
- EBULLATED BED UNIQUELY SUITED TO HANDLE COAL PYROLYSIS OIL PROCESSING DIFFICULTIES
  - SOLIDS IN FEED
  - FOULING TENDENCY OF FEED
  - HIGH DEGREE OF EXOTHERM
- TYPICAL OPERATION
  - YIELDS

C_1-C_4	GAS	5 WT %
C_5/350°F	NAPHTHA	12 VOL %
350/900°F	TURBINE FUEL	82 VOL %
900°F+	GASIFIER FEED	10 VOL %

  - HYDROGEN CONSUMPTION - 1500 - 2500 SCF/B
- DATA BASE EXPANSION AND PRODUCT QUALITY STUDIES THROUGH BENCH-SCALE UNIT OPERATIONS

TABLE 37. COIL™ PROCESS

- COMBINED H-OIL® AND H-COAL® OPERATIONS IN THE SAME REACTOR
- VIRGIN RESIDUAL PETROLEUM OIL USED TO SLURRY COAL
- BENCH-SCALE TEST RESULTS CONFIRMED

  PRODUCT COMPATIBILITY
  PROCESS SYNERGY
  UNIT OPERABILITY

- APPLICABILITY

  EASY INTEGRATION WITH EXISTING PETROLEUM FACILITIES

  H-OIL® PROCESSING OF VACUUM RESIDUE IS LIKELY TO BE APPLIED WIDELY

  REFINERIES ARE LIKELY TO HAVE COAL SUPPLY LINE ESTABLISHED TO MEET REGULAR ENERGY REQUIREMENTS

  ADDITION OF H-OIL® FEED (COIL™) IS THE EASIEST WAY FOR INDUSTRY TO ACCOMPLISH COAL LIQUEFACTION

Sid Thomson, Fluor Engineers and Constructors, Inc.: I noticed that the nitrogen contents in the H-Coal process is high. Isn't the H-Coal process a hydrocracking process?

Mr. Eccles: It's a thermal cracking process in the presence of hydrogen to which we are able to add hydrogenation components by adding more catalyst and by changing the reactor conditions. So there are two dimensions of it.

Mr. Thomson: What makes it so difficult to convert your nitrogen to ammonia and take it out of your product? Is it tied up in the coal in such a manner that it's difficult to free?

Mr. Eccles: It's tightly bound and there is a lot of it.

Mr. Princiotta: Have you done any measurements or do you have any feel for the potential toxicity of your H-Coal products?

Mr. Eccles: In terms of the quality of the particular products of the three major processes that have been discussed here, the SRC and the EDS and the H-Coal, if you talk about material in the same boiling range, they will probably be fairly similar. You are not going to want to allow routine skin contact with any of them and you are going to have the same kind of hygiene consideration as was said with regard to the materials in the coal-tar industry. They are really not much different than that. In the lighter part of the barrel, it's even less of a concern than that.

Mr. Princiotta: How about your commercialization schedule? Do you have any plans to go to a very large scale?

Mr. Eccles: One corollary of being a small outfit is that we are not going to commercialize anything like operating plants. We provide technology. We are working with Ashland Oil and it looks like they are going to commercialize this H-Coal process in the United States.

Mr. Princiotta: If they did, what would the timing look like?

Mr. Eccles: They are looking at timing following right on the heels of the SRC-II schedule that you saw. If the schedule prevails, it would be on-stream within a couple of years of the demonstration plant for the SRC-II.

Mr. Princiotta: Which is when, roughly?

Mr. Eccles: I think we are talking in the mid-1980s.

Mr. Princiotta: Do you think you would be the first direct liquefaction process to go on a commercial scale?

Mr. Eccles: Yes, when the Catlettsburg unit comes on, it will be the largest direct liquefaction unit anywhere. At 600 tons a day, it is 10 times the size of the Fort Lewis unit.

Mr. Princiotta then introduced Vernon W. Weekman, Jr., of Mobil Research and Development Corporation.

Mobil Oil Plans in the Area of Coal Liquefaction: Vernon W. Weekman, Jr., Mobil Research and Development Corporation.

I certainly appreciate this opportunity to discuss with you some of our work at Mobil. I'd like to discuss the conversion of methanol to gasoline. It does present a unique technology.

There are two modes to it, one starting with natural gas and reforming it to CO and hydrogen, that is, syngas; and the other with coal, which is gasified to form the syngas. Both methods are outlined in Figure 29.

The first method might be practiced, for example, in regions that have an excess of natural gas, such as Saudi Arabia, Indonesia, or New Zealand.

Of course, the coal mode is preferred in this country. We use conventional methanol technology to convert syngas to methanol. I'd like to focus, however, on just the conversion of methanol to gasoline. Figure 30 shows roughly the chemistry of the process. Methanol is composed of a hydrocarbon part and water part. You literally separate them and take the hydrocarbon part and rearrange it into high-octane gasoline.

Figure 31 is a rough energy and mass balance. For every 100 tons of methanol, we get 44 tons of hydrocarbon and 56 tons of water. In the energy balance, if we have 100 Btu of methanol, we get 95 Btu in the hydrocarbons, and zero in the water. The 95 Btu is the thermodynamic ideal and a few percent are also lost in process inefficiencies.

In Figure 32, the reaction path is shown. The methanol quickly comes to equilibrium with the dimethyl ether and light olefins are formed, again rejecting water. The olefins then are rearranged into C_5 plus olefins, which further rearrange into paraffins and cycloparaffins and aromatics, which are typically found in gasoline.

The secret of this process is really the catalyst, which is a unique new zeolite discovered a few years ago. If you remember your chemistry, silicon forms a tetrahedral structure. These can form intricate networks.

Figure 33 shows another view of the same kind of structure, again, the same atomic structure, but highlights the fact that there is an intricate set of interconnected core structures inside the zeolite.

Recently, we have revealed the detailed structural nature. We have a set of straight and crooked channels. The methanol molecules have equal access into both of those channels. The unique feature, though, is that the molecules that are formed are limited by the size of the pores and only certain sizes can be formed and leave. This happens to be just at the endpoint of gasoline. So we make nothing greater than gasoline from the methanol.

Figure 34 shows the penetrability or diffusivity inside the zeolite of some typical compounds. The cyclohexane is way up on the scale, over 100. By the time we get to xylene, we are down a couple of orders of magnitude. With butylbenzene, we are down almost another order of magnitude. With trimethylbenzene, we are down even farther.

The key here is that when you reach the size of the polynuclear aromatics, there's no longer any room for them to form. So, we make essentially no polynuclear aromatics.

Figure 35 shows the reaction path in terms of time to react. On the left is a scale of the weight percentage of products. Methanol is very rapidly converted to dimethyl ether which, in turn, forms paraffins, olefins, and aromatics. Olefins form first and then they peak and disappear, leaving essentially paraffins and aromatics. It is also possible to stop and produce olefins at a given point in the reaction path.

Table 38 describes the current status of the process. We have done an extensive amount of adiabatic fixed-bed work in our laboratories in conjunction with DOE. We have also performed long-term aging tests on bench-scale units. We have operated for 243 days successfully and at that point we projected that the catalyst still had approximately one year's life.

The cycle lengths between regenerations are roughly 15 to 20 days. A small amount of carbon is laid down and we have to regenerate periodically. We are ready to commercialize this process in the fixed-bed version.

I just came back from New Zealand where we were negotiating with the New Zealand government for a fixed-bed unit for the conversion of natural gas. They have large amounts of gas in the Maui Gas Fields. New Zealand's balance of payment problem is similar to ours and they are proposing to convert natural gas into gasoline.

We have another reactor version where we put the catalyst within tubes. In this case we remove the heat of reaction by a transfer through the tubes to a heat exchange medium. This version has interest because it can be scaled up quite readily. We are also working on a fluid-bed version. We have already completed, with DOE participation, a four barrel-a-day pilot plant. We are currently negotiating with DOE, the German Federal Government, and two German companies for a large scale-up to 100 barrels a day. This would be located in Germany, on the Rhine. The last stage of negotiation is being reached now; we hope that agreement will be signed very shortly.

We are building the 100 barrel-a-day plant because we are concerned about the scalability of fluid bed. You have to be concerned about the catalyst contacting patterns and resulting efficiency of these reactors. We are very confident that fixed bed can be scaled up directly to commercial size. The fluid bed requires additional steps. For the long range in this country, we think it would be an advantage to build the very large-scale plants in the fluid-bed mode because of the scale-up advantages.

Table 39 shows some of the yields from the four barrel-per-day unit. You will notice that temperature, pressure, and space velocity are quite modest. We achieved almost 100 percent conversion of methanol in this fluid-bed reactor. It was quite a successful scale-up. Typical yields are also shown.

The product properties shown in Table 40 are of interest because we are talking about a gasoline that actually is more environmentally acceptable than conventional gasoline because there is no sulfur or nitrogen present.

A later figure indicates that we are well within the range of conventional gasolines, in terms of composition, with a very high clear octane. One of my friends at General Motors saw this and was overjoyed. He said, "We can build a much simpler catalytic muffler."

Durene content is 3.8 percent. Durene is a monoaromatic with four symmetric methyl groups. It has a very high melting point. We are concerned about it because in high concentrations it can cause driveability problems.

We find that when we keep the concentration below 5 to 6 percent, there is no driveability problem with the car. It has a very high octane number. In fact, it's a desirable constituent, if you can keep down the concentration.

Table 41 takes a closer look at the composition of the synthetic gasoline and compares it with some 40 samples of conventional gasoline from all around the United States. Gasoline from the methanol process has considerably less benzene than typical commercial gasolines. The federal specification is 5 percent.

Naphthalenes are polynuclear two-ring aromatics. The levels are very, very low in the synthetic gasoline. The nature of the catalyst doesn't permit them to be formed in any higher concentration. Typically, the levels are two to three percent in FCC (catalytic cracking) gasolines, which constitute 40 to 50 percent of the U.S. gasoline pool.

In terms of the total aromatics, olefins, and saturates and paraffins (cycloparaffins here), we are well within the range of the conventional gasoline. In fact, I would defy you to take this gasoline and distinguish it from a natural gasoline, except possibly for the durene content.

Table 42 shows the relative toxicity of some components. The vapor pressure is crucial, because that determines how much we have present, say around a gasoline pump.

Benzene has the highest vapor pressure; xylene has less. Durene is almost a solid. It has a very, very low vapor pressure. Benzene is a suspected agent for carcinogenicity as well as some other problems. As you add methyl groups, there is evidence that these components become less toxic, but this has not been established. Durene, however, having four methyl groups, should be even less toxic.

Table 43 shows the content of the water phase. As stated earlier, we made 56 tons of water for every 44 tons of hydrocarbons. This water phase does have a small amount of acids and aldehydes, totaling about 0.44 weight percent of the water, typically. Removal is well within the range of current technology. You neutralize it with a caustic and send it to a pond to be chewed up by bacteria.

In summary, I think we have a process that probably is as good a neighbor as a refinery. Certainly in the area of product properties, it is an improvement over conventional gasoline.

Dick Passman, DOE: What do you think is the possibility of a scale-up to 50,000 barrels a day from your 100?

Mr. Weekman: If you have the money, we are ready to build a fixed-bed unit today. We made that proposal to New Zealand for a large, full-scale plant.

Mr. Passman: What about the fluidized bed?

Mr. Weekman: The fluidized bed, we think, requires further scale-up. We would recommend going to the 100 barrel-a-day size before going to the full demonstration plant, say in the 5,000 or 10,000 barrel-a-day size. We feel that's a necessary step to go through. The fixed bed, however, is ready today.

Mr. Princiotta: What other advantages does the fluidized bed have?

Mr. Weekman: The very large-scale fluid-bed plants could have lower costs. That is the key advantage we see on scale-up to very large plants, 50,000 barrels a day and up.

Mr. Princiotta: I wonder if you could characterize the state of the coal-to-methanol technology? Have you looked at the cost of adding those two pieces together? How might it compare with some of the direct liquefaction processes, for example?

Mr. Weekman: Yes, we have looked at this. We have done a recent study for DOE, where we looked at the cost of going all the way from coal to gasoline.

Using conventional Lurgi dry-ash gasifiers, and the Lurgi methanol synthesis process, which is conventional technology, we used a fixed bed for the Mobil part of it. We compared this not with the direct liquefaction route, but with Fischer-Tropsch. Here we found we had roughly 13 percent less capital required for the methanol gasoline route than for Fischer-Tropsch.

We were using 1977 dollars for a Wyoming location. That report showed that we are talking about $.80 to $.90 a gallon of gasoline, for 100 percent equity financing for the Mobil methanol process, and about $1.00 to $1.20 a gallon for Fischer-Tropsch on the same basis.

We have not made a direct comparison with the liquefaction, although DOE has argued that they are roughly comparable right now.

Mr. Princiotta: Would you characterize the state of the art in coal-to-methanol technology?

Mr. Weekman: Coal to methanol can be built with conventional, existing technology. You can take an existing Lurgi dry-ash gasifier, an ICI methanol process, the DuPont methanol process, and go with it today. That's conventional technology.

Mr. Princiotta: What are your plans for any large scale-up of this technology in this country?

Mr. Weekman: We are considering some conceptual design for a 50,000 barrel-a-day plant.

Mr. Princiotta: It sounds as though, if the Energy Security Corporation gets underway and if they provide enough incentive, you and

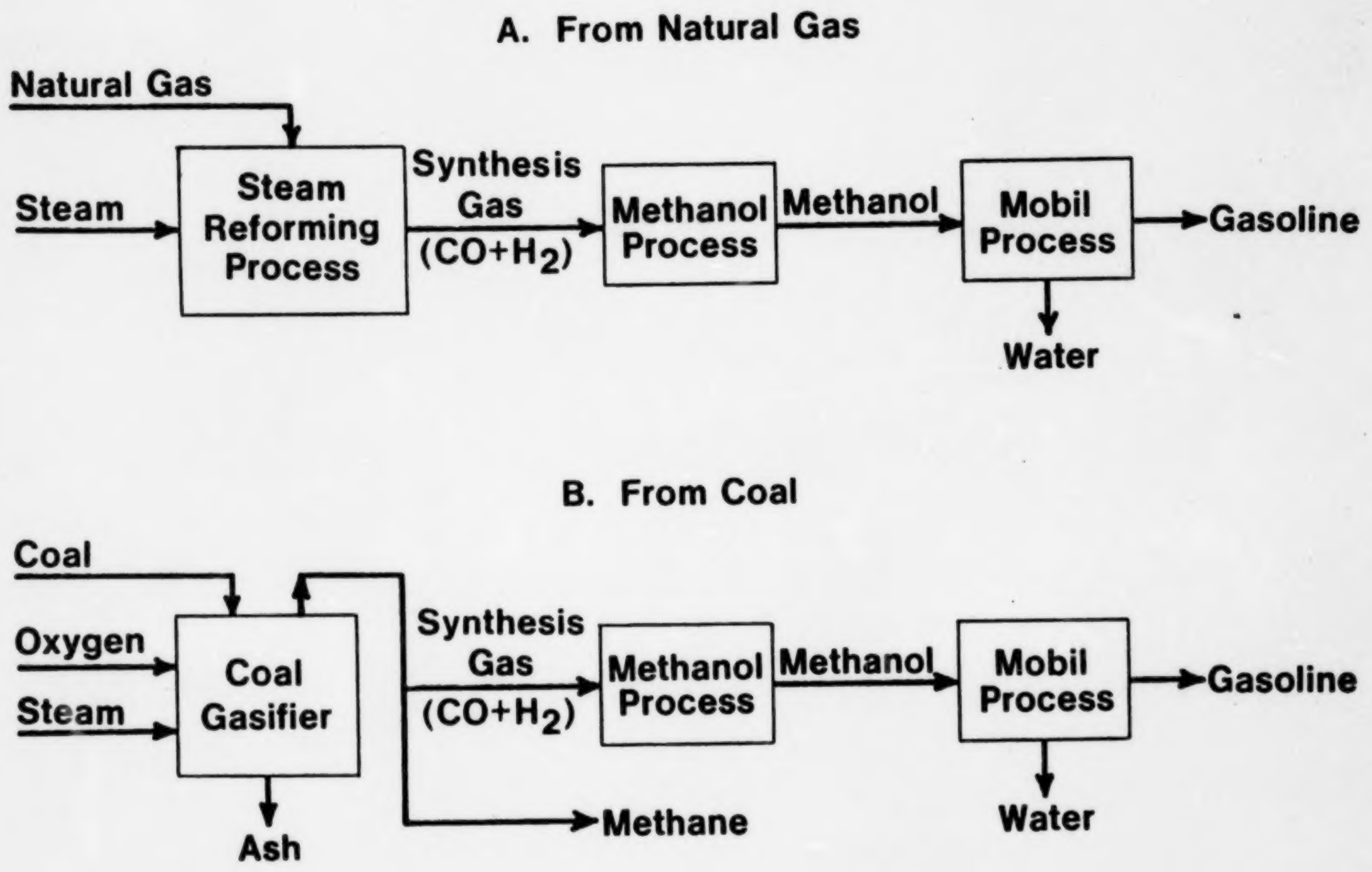

A. From Natural Gas
Natural Gas
Steam
Steam Reforming Process
Synthesis Gas ($CO+H_2$)
Methanol Process
Methanol
Mobil Process
Gasoline
Water
B. From Coal
Coal
Oxygen
Steam
Coal Gasifier
Ash
Synthesis Gas ($CO+H_2$)
Methanol Process
Methanol
Mobil Process
Gasoline
Water
Methane

Figure 29. Manufacture of Synthesized Gasoline

$$\text{Methanol}\begin{bmatrix}\text{Hydrocarbon} + & \text{Water}\\ \text{Like Part} & \text{Like Part}\end{bmatrix}\xrightarrow[\text{Process}]{\text{Mobil}}\text{Gasoline} + \text{Water}$$

$$CH_3OH\left[CH_2 \cdot H_2O\right]\xrightarrow[\text{Process}]{\text{Mobil}}\left[CH_2\right]_n + H_2O$$

- Wrings Out the Water
- Rearranges the Hydrocarbon Part Into High Octane Gasoline

Figure 30. How the Mobil Process Works

CHEMISTRY OF METHANOL CONVERSION TO GASOLINE

	FEED		PRODUCT
	nCH_3OH	→	$(CH_2)_n$ + nH_2O
	METHANOL	→	GASOLINE FUEL GAS + WATER
MATERIAL BALANCE:	100 TONS	→	44 TONS + 56 TONS
ENERGY BALANCE:	100 BTU	→	95 Btu + 0 Btu

Figure 31. Chemistry of Methanol Conversion to Gasoline

REACTION PATH

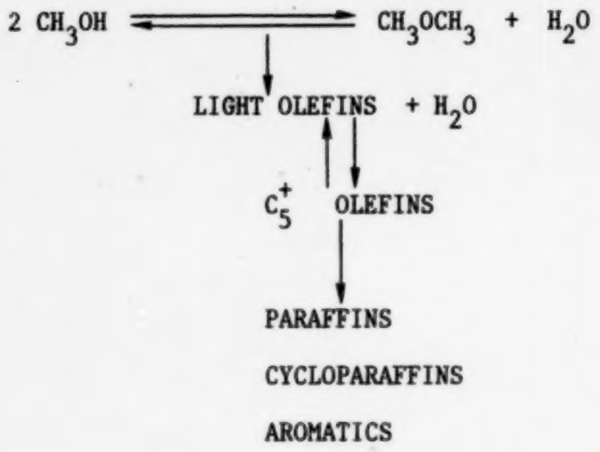

$2\ CH_3OH$
$CH_3OCH_3 + H_2O$
LIGHT OLEFINS $+ H_2O$
C_5^+ OLEFINS
PARAFFINS
CYCLOPARAFFINS
AROMATICS

Figure 32. Reaction Path, Methanol to Gasoline

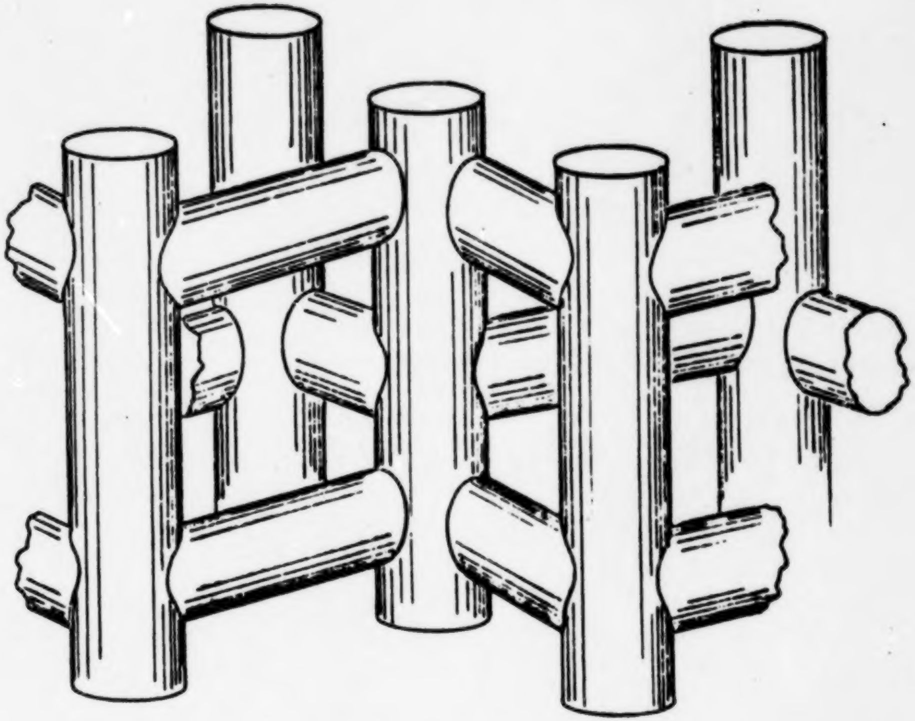


Figure 33. Approximate Model of Pore Structure of New Zeolite

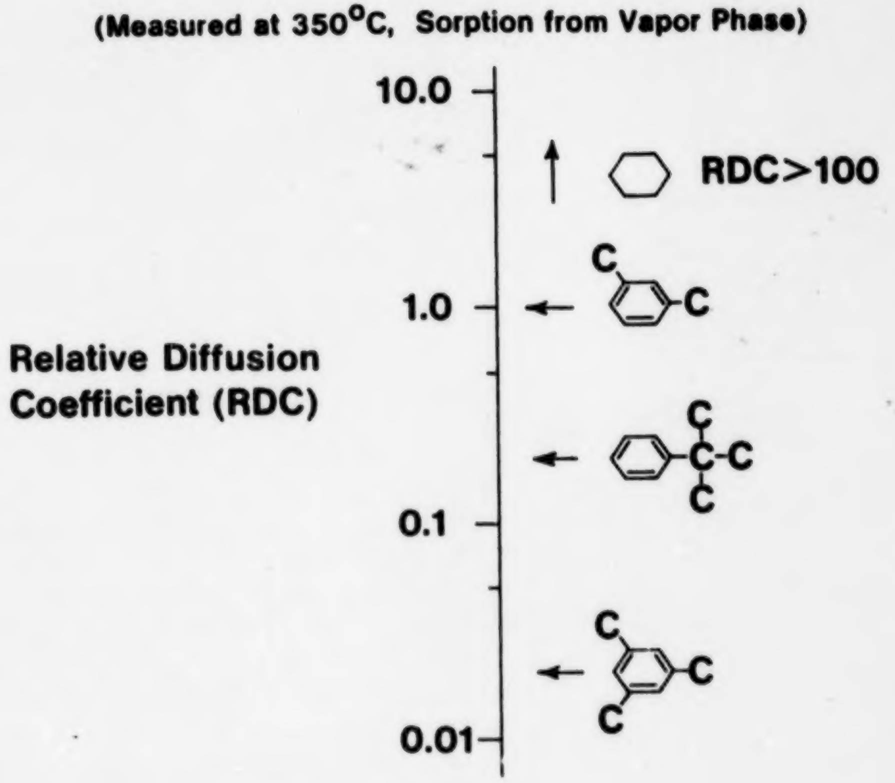


Figure 34. Penetrability of New Zeolite by C_6 to C_{10} Hydrocarbons

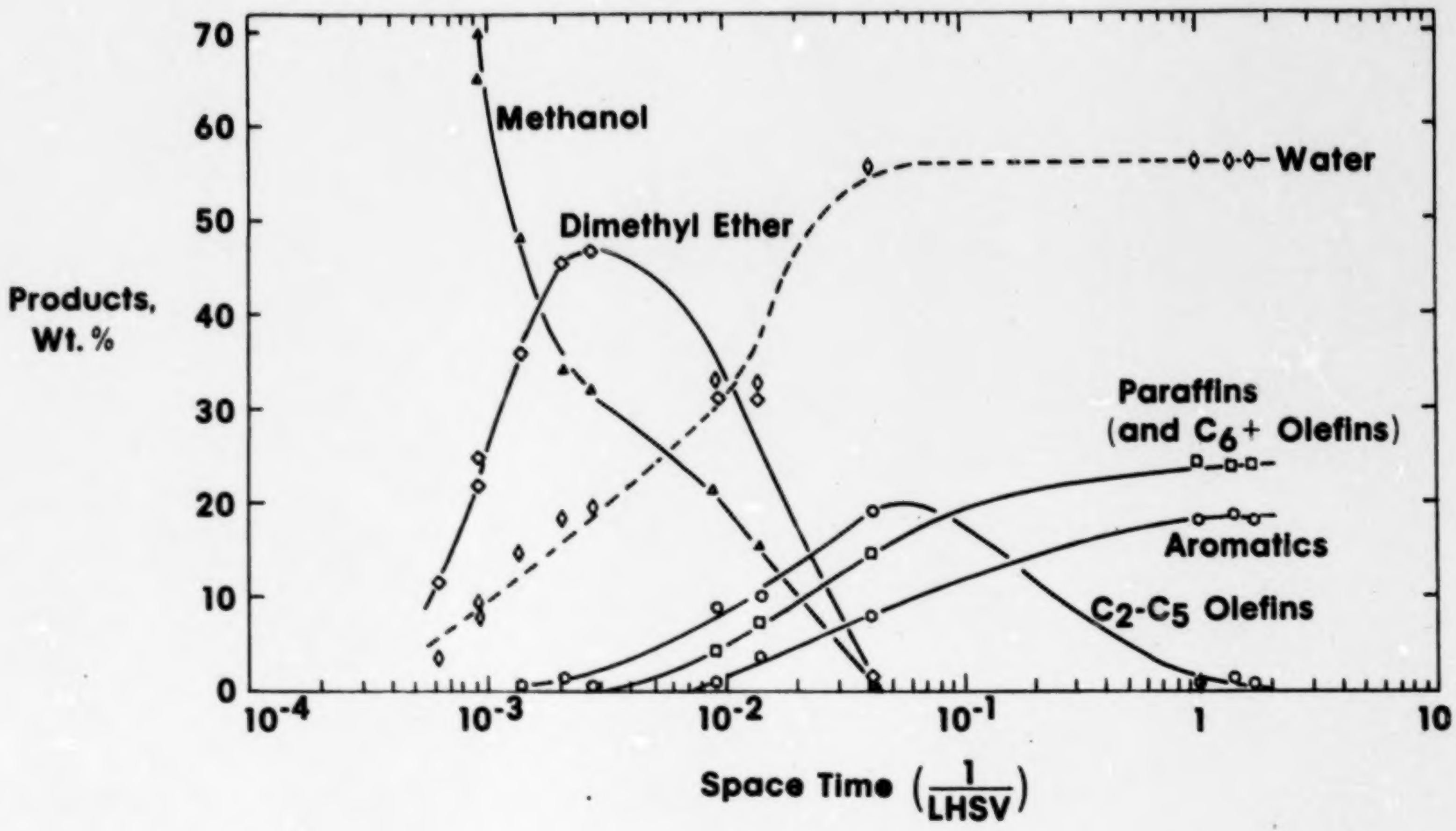


Figure 35. Effect of Space Velocity

TABLE 38. STATUS OF MOBIL PROCESS

- ADIABATIC FIXED BED REACTOR
  - DEVELOPED ON BENCH-SCALE UNITS
  - LONG-TERM AGING TEST COMPLETED
  - READY FOR COMMERCIALIZATION

- HEAT EXCHANGE TUBULAR REACTOR
  - EXPERIMENTAL PROGRAM IN PROGRESS

- FLUID BED REACTOR
  - DEVELOPED ON A 4 B/D PILOT PLANT
  - BEING SCALED-UP TO A 100 B/D UNIT

TABLE 39. YIELDS FROM FOUR-BARREL-A-DAY PILOT PLANT

Average Bed Temperature, °F	775°F
Pressure, psig	25
Space Velocity (WHSV)	1.0
Methanol Conv. to Hydrocarbons	99.8%
Hydrocarbon Product, Wt %	
Light Gas	5.6
C_3's	10.9
C_4's	23.5
C_5 + Gasoline	60.0
	100.0
Gasoline (Including Alkylate)	
(96 R + 0, 9 RVP), Vol. %	88.0
LP Gas	6.4
Fuel Gas	5.6
	100.0

TABLE 40. TYPICAL PROPERTIES OF FINISHED GASOLINE

Components, Wt %		
Butanes	3.2	
Alkylate	28.6	
C_5^+ Gasoline	68.2	
	100.0	
Composition, Wt %		
Paraffins	56	
Olefins	7	
Naphthenes	4	
Aromatics	33	
	100	
Octane	**Research**	**Motor**
Clear	96.8	87.4
Leaded (3 cc TEL/US Gal)	102.6	95.8
Reid Vapor Pressure, psig	9.0	
Specific Gravity	0.730	
Sulfur, Wt %	Nil	
Nitrogen, Wt %	Nil	
Durene, Wt %	3.8	
Corrosion, Copper Strip	1A	
ASTM Distillation, °F		
10%	117	
30%	159	
50%	217	
90%	337	

TABLE 41. COMPARISON OF GASOLINE FROM METHANOL WITH CONVENTIONAL GASOLINE

Components	Gasoline From MTG	Commercial Non-Lead	Federal Specification
Benzene (Wt %)	0.2	0.4 - 3.0	5.0
Naphthalenes (Wt %)	0.2	2 - 3*	--
Aromatics (Vol %)	28	15 - 48	--
Olefins (Vol %)	12	2 - 24	--
Saturates (Vol %)	60	49 - 77	--

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*Typical gasoline from catalytic cracker

TABLE 42. RELATIVE TOXICITY OF SOME GASOLINE COMPONENTS

	Benzene	Toluene	O-Xylene	Ethylbenzene and Other Xylenes	Durene
Vapor Pressure MM HG (26-32°C)	100	30	10	10	.2
TLV*, PPM	10	100	100	100	Not Been Established
Carcinogenic Effect	Suspected**	◄—— Not Been Established ——►			

*"Threshold Limit Values for Chemical Substances in Workroom Air." Adopted by ACGIH (Am. Conf. of Ind. Hygienists) in 1979.

**"Occupational Exposure to Benzene," HEW Pub. No. (NIOSH) 74-137.

TABLE 43. AQUEOUS PHASE ANALYSIS FROM METHANOL-TO-GASOLINE PILOT PLANT

Components	Wt% in H_2O
Formic Acid	.2
Acetic Acid	.02
Acetaldehyde	.01
Acetone/Propionaldehyde	.15
Methyl Ethyl Ketone/N-Butylaldehyde	.05
Methanol	.01
	.44
Acid Number (mg KOH per g)	1.5

others might be willing to go commercial.

Mr. Weekman: I think that's a very good possibility.

Fred Glaser, DOE: About a year and a half ago, Mobil came out with the relationship between the cost of methanol and the cost of product gasoline. I think the relationship was 2.4 times the MeOH cost plus a nickel.

Mr. Weekman: Yes, that was the formula published in our DOE report.

Mr. Glaser: Does that relationship still hold or has it been modified?

Mr. Weekman: Well, we have had to modify it.

Mr. Princiotta: Can you explain those numbers?

Mr. Weekman: Yes. In our DOE report SE-2447-13, we show the formula to be gasoline cost - a [cost of MeOH] + b where a is the stoichiometric factor (volume of MeOH/volume of gasoline) and b reflects the process cost plus the by-product credits.

Mr. Glaser: Do you have the order of magnitude for the factors?

Mr. Weekman: The DOE Shriner Report does have an update on those numbers.

Mr. Princiotta: The nickel is what you add to the cost of the methanol?

Mr. Glaser: In cents per gallon, it is 2.4 times the cost of methanol in cents per gallon, plus a nickel.

Mr. Princiotta: The incremental cost is only five cents.

Mr. Weekman: In the latest report (SE-2447-13), we now show the a = 2.44 while the b = $.05 a gallon. The b factor changed because of cost and by-product credit changes. It is probably too simplistic a formula to rely on and must be updated periodically for inflation and cost changes.

Mr. Princiotta: Why do you feel you need to be cheaper with your fluidized bed versus your conventional?

Mr. Weekman: We are talking about huge volumes here. A penny per gallon is a huge factor on this scale. We make a living on a penny per gallon in this industry, don't forget.

Mr. Princiotta: Some say a little more than that. I couldn't resist that one, sorry.

Bob Hangebrauck, EPA: On that same DOE study that compared costs, could you comment on the energy conversion efficiency of Fischer-Tropsch versus methanol?

Mr. Weekman: Yes, using high heating values from coal to gasoline via the methanol-to-gasoline route, was about 63 percent thermal efficiency.

The Fischer-Tropsch route was about 58 percent. So we have an advantage in thermal efficiency over Fischer-Tropsch on the same basis.

In the natural gas case, we have an even greater advantage than in the methanol case, because Fischer-Tropsch makes methane and that has to be recycled. This significantly lowers the thermal efficiency for Fischer-Tropsch.

Mr. Princiotta: Can you define the efficiency you indicated?

Mr. Weekman: Using the high heating value of the coal, the high-heating value of all the products, the efficiency is the number of Btu in all the products divided by the Btu content of the coal and any external power used.

Mr. Princiotta: That seems like a fair direct cost, and that's a little surprising.

Mr. Princiotta then introduced Barnet Groten of Texas Eastern Corporation.

Texas Eastern Corporation Plans in the Area of Coal Liquefaction: Barnet Groten, Texas Eastern Corporation.

The Fluor Corporation and Texas Eastern Corporation have covered some of the same ground from time to time and Mr. Thomson and I have combined our presentations somewhat.

Before discussing Texas Eastern's plans in the area of coal liquefaction, I would like to preface those remarks with some background on Texas Eastern's energy activities in general. We are perhaps best known for our interstate gas transmission systems - a major line serving the Northeast from the Gulf Coast, and another line serving the Western states from west Texas. We also operate a liquid products line from the Gulf to the Northeast and Midwest, have a refinery in east Texas and retail LPG on the East Coast. In addition, the company has a major program in oil and gas production, domestic, onshore and offshore, and around the world. We are currently quite active in several areas in the North Sea. New ventures are being developed in coal slurry transport and a methanol project is underway in Saudi Arabia.

R&D activities include investigations into the production of heavy oil, secondary and tertiary recovery of petroleum from conventional reservoirs, development of the so-called unconventional gas sources, and of course investigations in synthetic fuels technology. All this is by way of saying that our participation in synthetics results from broad knowledge of the energy industries, and is not based on a brief glance at the field.

Texas Eastern's involvement in synthetics goes back to the 1960s. Our first major attempt to develop a synfuels plant was the WESCO project, a joint venture between Texas Eastern and Pacific Lighting to build a synthetic natural gas plant in northwestern New Mexico. This project was eventually terminated because of the lack of federal loan guarantees, and the inability to come to an agreement with the Navajo Nations on a site lease.

During the intervening years, our background in synthetics has been consistently updated. We recognize that coal-based synthetics are not the only answer to America's current energy uncertainties. However, they are certainly part of the answer, and a part we cannot afford to overlook any longer. We have extensive supplies of coal, and technology exists to convert it to gases and liquids that are compatible with our current (quite extensive and expensive) energy distribution systems.

These conversion processes are complex, and learning how to build and operate these plants will take time. We feel the United States has already lost much valuable time, between the embargo period in 1973 and the Iranian situation and gas lines in 1979. I sincerely hope we don't repeat past mistakes. The sooner we start building these plants and learn how to run them in a safe and environmentally acceptable manner, the more confident we will be that we are on at least one of the roads to a solution to the energy problem. To this end we strongly support legislation now working its way through Congress that will provide suitable synfuels commercialization incentives.

If the country is to start developing synthetic liquids from coal, the question arises as to which technology shall be employed. There certainly has been substantial debate on this subject during the past few years. In our view there are three processes that can be built now, on which corporations would be willing to accept the technological risks. These are the Lurgi gasification followed by methanation to SNG, production of methanol, and Fischer-Tropsch to liquid fuels. Texas Eastern is currently investigating projects employing each of these technologies.

I would like to make a few remarks about the environmental aspects of these three approaches to synfuel manufacture. In the case of gasification, several U.S. projects, WESCO included, advanced far enough to have had environmental impact statements prepared on the process. There is something over $100 million of various companies' funds tied up in gaining the knowledge necessary to get as far as EISs on these projects. While there would obviously have to be some additional site-specific fine tuning performed for future EISs, we could at least be assured that a significant head start has been made in environmental evaluation of the Lurgi gasification process.

To produce methanol we essentially have the same gasifiers and gas clean-up in the front-end. The back-end of the plant employs a process that differs in no substantive way from that which is in use in dozens of plants around the world. It would be fair to say that the environmental aspects of the methanol module in a coal-to-methanol plant are as well understood, no more, no less, as those of any methanol plant based on natural gas reforming.

We come then, finally, to the Lurgi gasification front-end followed by the Fischer-Tropsch liquefaction process. Texas Eastern has recently contracted with SASOL, Limited -- Fluor will be doing the engineering for SASOL under this contract -- to evaluate the cost of building a Fischer-Tropsch plant at a U.S. site, employing U.S. coals, and conforming with U.S. environmental requirements.

In the Fischer-Tropsch process, the purified gas from the Lurgi gasifier is reacted in a catalytic fluidized-bed reactor to produce a wide range of crude products. The product slate includes LPG, gasoline, diesel and fuel oils, jet fuel, chemicals such as ethylene and other olefins, and some oxygenated species, predominantly low-molecular-weight alcohols. The technology for product recovery and clean-up downstream of the Synthol reactor is a combination of standard refinery and petrochemical processes. The Synthol processes also produce some additional methane which can either be used as such or reformed into additional synthesis gas and recycled in the process. Once again, the technology for reforming is the same as that currently used in many plants around the world.

The first SASOL plant, built over 20 years ago at Sasolburg, South Africa, is a benchmark in the conversion of coal to synthetic liquids. Driven by economic necessity, SASOL has examined all of the products, co-products, and by-products produced by this plant since its inception and has a thorough understanding of what can be made either intentionally or accidentally. Their knowledge of, and confidence in this process are such that their two new plants are based on essentially the same process, seasoned with the experience of 20 years of intensive process development and R&TD.

It consistently amazes me that people who are familiar with the process industries (chemical, petrochemical, refining) don't recognize the phenomenal value of 20 years of operational experience. Comparisons are consistently made between the Fischer-Tropsch process and other newer processes that have barely gone beyond the pilot or demonstration phases.

It is common to compare Fischer-Tropsch economics based on an operating plant, with projected costs for processes for which the full-scale reactor hasn't even been engineered. These are specious comparisons at best. The same situation holds with respect to the environmental aspects.

One can conjecture about the effects of new technology, but one can see the results of a plant that's currently on-stream.

In 20 years of operation, one gets to know the peculiarities of a process. Moreover, from an environmental and occupational health point of view, that is a sufficiently long period for any chronic "surprises" or long-term cumulative effects to have made their presence known.

I might add parenthetically for those not familiar with the environmental situation in South Africa that the current and future SASOL plants stand in the middle of the Transvaal Watershed and are reasonably close to the major population center of the country. No small amount of effort has been expended to assure that the environmental impact of these plants is consistent with that location.

In summary, our corporate activities in synthetic fuels are directed toward production of synthetic natural gas, methanol, and Fischer-Tropsch liquids from coal via gasification coupled with various finishing steps - all using commercially proven technology. In all cases we are producing a slate of fully characterized products. There is an important distinction to be made between such processes (the so-called indirect technologies) and the direct technologies, which involve a synthetic crude product that is far less fully characterized and a process which has reached neither the scale nor the endurance level of any of the indirects.

Dick Passman, EPA: Can you tell us what kind of yields per ton of coal you get or expect to get from your transportation fuel?

Mr. Groten: That's a tough question to answer off the cuff. We certainly have the numbers on those things, but they vary too much from one coal to another, or from one plant configuration to another, to make it possible to toss out a single figure that is typical for the process.

In our early screening studies, we took a look at the question of thermal efficiency, which really is not a very good measure, and we concluded that the thermal efficiencies of all the major contending processes are close. I won't get into an argument with anybody over a percentage point here and there; they all seem to run around 50 percent.

In the real world, not in the arguments among engineers, if you can beat the process on time, you are going to beat that thermal efficiency. This is an inflationary period, and it's amazing again how few people have gotten out of the three-percent-per-year mentality in looking at these plants. In an inflationary period, your costs go up sharply while you are building, requiring capital. When you get to the point where you are on-stream, you feel the O&M inflationary effects.

You start with two processes, Process A, which is more expensive at the beginning, and Process B, which is initially less expensive, but takes longer to get onstream. Process A may not be as satisfying to an engineer as B, but it is going to make a lot more sense to the business world, to the consumers, and to the country if it is brought on-stream earlier, that is, at a lower capital cost. It's the kind of concept that people very often overlook. A few points' difference in efficiency is traded off for the long-term economies of lower capital requirements.

Bill Rhodes, EPA: Can you discuss why you have apparently eliminated Koppers-Totzek from your considerations and have gone strictly with Lurgi?

Mr. Groten: We didn't eliminate it. We considered it quite strongly. The Koppers-Totzek gasifier is undergoing some changes and improvements now. We are, however, comfortable with Lurgi because we know it very well. The SASOL project is using it.

I don't want to delve into proprietary areas, but there is a lot more to these gasifiers than is generally published. You have to know how to live with a piece of machinery like that. By way of improvements, I might add that there is a slagging Lurgi under development, that will offer additional versatility and economy.

Terry Thoem, EPA: Given your optimism on the technology, what does Texas Eastern need to go commercial?

Mr. Groten: Basically, synfuels processes will turn out a product which will not compete with today's petroleum products in the free market. Therefore, some structure has to be provided so that, until coal-derived fuels can be competitive, they are supported, subsidized, or whatever word you want to use. The financial risks, which are enormous in these plants, must be mitigated.

No corporation can afford to assume the risks of new environmental requirements, changing economics, or any other kind of unforeseen changes. The cost of the individual plant would just jump too high if the private investor had to cover all these risks.

Dominic Palazzo, Mobil: I couldn't agree with you more about making economic comparisons between operating plants and ones that are on the drawing board.

But just to put into perspective the estimates that were prepared by Mobil on that DOE report, approximately 90 percent of that investment is based upon equipment for processes that are already existing. Only about 10 percent of it, which is the Mobil part of it, is really what you would call developmental.

You would have to go a long way to qualify your estimate for 10 percent of the plant to swing 30 cents a gallon on the product. I am not saying that you have.

Mr. Groten: Providing the 30 cents is accurate. I'm not sure I agree with it. I don't think this is the place to go into the details of it, but like all other studies made, there are assumptions set out in the beginning. I am not sure that those assumptions, while they may have been theoretically correct, necessarily reflect a plant in the real world.

Norb Jaworski, EPA: Your bottom line is, the technology is here, give us the dollar support and a fast track and we can meet the Presidential plan by 1990.

Mr. Groten: Maybe not quite so glibly, but I think you are getting pretty close to it. I'm not sure about meeting the President's target; that involves more than my company can do. We are willing to do our part, we will be one of the contributors. It's another question as to whether, if everybody got marching right now, those targets would be met. It would be difficult but possible, I would say.

Vern Weekman, Mobil: I just want to comment that our part of the technology may not be as radical as was implied. We recently announced that we have 21 commercial process units in operation today, utilizing ZSM-5 family of catalysts. All of these have been scaled up well within the bounds of which the methanol was to be scaled up. So, we feel it is well within our bounds of experience.

Mr. Groten: We have talked with Mobil considerably about the Mobil process, as I mentioned. We do have an interest in developing a methanol plant. That doesn't mean it will stop with the methanol plant. The Mobil process is ready, and when it is appropriate, it can be used very easily.

Mr. Weekman: These are petrochemical plants?

Mr. Groten: Yes.

Mr. Princiotta: It seems to me you are in a unique situation. The objective observers of the coal liquefaction processes are out there. Do I sense that you are very skeptical about the correct processes and their ultimate contribution?

Mr. Groten: What I am skeptical about is the fact that the direct processes have been treated as if they are available today. They are not. I don't think anybody who has talked about the direct processes here today said that.

The direct processes certainly need to be developed. Companies currently involved with the indirect processes are also looking at direct processes down the road. I will have to agree with the statement that when we have a mature industry in the country, there is going to be a mix. I might add that the mix is going to be determined not just on how well these things compare on paper but on what kind of site and what kind of coal is involved.

Again, thermal efficiency makes marvelous paperwork, but if you look at the difference between any two sites in this country for a given plant, you will find a bigger variation in the economics there than you will in the thermal efficiency. This again is a reality.

Mr. Princiotta then introduced Sid Thomson of the Fluor Corporation.

Fluor Plans in the Area of Coal Liquefaction: Sid Thomson, The Fluor Corporation.

The Fluor Corporation has gained significant experience in coal liquefaction, which enables us to recommend the coal liquefaction process most suited to the client's site location and marketing situation. Our goal is to continue to upgrade our skills in the engineering and construction of environmentally acceptable coal liquefaction plants.

The most significant coal-to-liquids activity in which Fluor is presently participating is the SASOL projects with the South African government. Through our experience with SASOL and other projects, we have found that environmental impacts resulting from the indirect processing of coal to liquids by the Fischer-Tropsch process can be mitigated by proper design based on knowledge presently available.

The front end of the complex is the gasification section, where one of several processes such as Texaco's or Lurgi's may be used. This discussion will be confined to the Lurgi process.

Discussions of the gasification section will be related to the WESCO project, for which an uncontested Environmental Impact Statement was issued and for which a permit to operate and construct was received from the State of New Mexico.

Figure 36 is a block flow diagram of the gasification section using the conventional Lurgi gasifier. The most desirable reaction in the gasifier when using the Synthol process is the production of carbon monoxide and hydrogen from the reaction of coal, oxygen, and steam.

Unfortunately, as with most organic reactions, a variety of side reactions occur, producing numerous other products that are less desirable either because of their lack of market value or because they are difficult and expensive to separate. Carbon dioxide, hydrogen sulfide, ammonia, phenols, naphtha, creosote, residual oil, pitch, and ash are those less desirable by-products resulting from the coal gasification reaction.

During the vapor cooling and condensing step, various products are condensed or absorbed in the water as the steam is condensed. These products are ammonia, phenols, naphtha, creosote, residual oil, and pitch. Some of the carbon dioxide and hydrogen sulfide, along with insignificant amounts of methane, hydrogen, and carbon monoxide, are also absorbed by the water and hydrocarbons as they condense.

The vapor phase from the cooling and condensing operation, consisting mainly of hydrogen, carbon monoxide, methane, carbon dioxide, and hydrogen sulfide, is processed in the Rectisol Unit. The carbon dioxide and hydrogen sulfide are separated from the raw gas, leaving the carbon monoxide and hydrogen-rich gas as feed to the Synthol unit.

The mixed liquid phase from the vapor cooling and condensing step is processed in the oil and water phase separation unit. The water phase is processed in the phenosolvan and ammonia recovery units to recover phenols and ammonia. Hydrogen sulfide and carbon dioxide gases removed during the processing are routed to the sulfur plant, where the hydrogen sulfide is converted to elemental sulfur. The oil phase is processed in the tar distillation unit to separate naphtha, residual oil, and pitch.

Figure 37 is a block flow diagram of the gas-to-liquids section and illustrates the conversion of carbon monoxide and hydrogen into the various Synthol liquids and their separation into the various products.

The raw gas is processed through the Fischer-Tropsch synthesis reaction, where the carbon monoxide and hydrogen are reacted to form various alcohols, ketones, and hydrocarbons. The Fischer-Tropsch processing scheme separates the products into four primary streams: tail gas, oxygenated hydrocarbons, light oil, and decant oil.

The tail gas stream contains light hydrocarbons and carbon dioxide. The carbon dioxide is removed in a carbon dioxide removal step and the light hydrocarbons are separated into methane, C_2 hydrocarbons, and C_3's and heavier.

The methane, when the output of hydrocarbon liquids is being maximized, is reformed to produce hydrogen for recycle to the Fischer-Tropsch process.

Ethane-ethylene may be used as feed to an ethylene unit, and C_3's and heavier may be utilized as feed for the polymerization unit for making a gasoline blend fraction.

The alcohol streams contain a wide range of alcohols and ketones, which may be separated by further processing based on the market demand.

The light oil fraction is separated into C_5 hydrocarbons, naphtha, and heavy oil. The heavy oil is fed to the vacuum distillation unit for further separation. The decant oil, along with the heavy oil from light oil fractionation, is fed to the vacuum distillation unit for separation into distillates and fuel oil.

The propane-propylene, C_5 - C_6 hydrocarbons, naphtha, and distillate may be converted to gasoline by further processing.

Figure 38 is a schematic diagram of the WESCO Project, indicating the environmental control units in the gasification section of the plant. The primary sources of sulfur emissions are: the hydrogen sulfide from the coal gasification unit, Rectisol unit, gas-liquid separation unit, and the phenosolvan unit; and the sulfur dioxide in flue gases from combustion equipment.

Collection of the vent gases from the coal gasification reactors and routing to the appropriate treatment process is used to reduce the emissions from this section of the plant.

On the WESCO Project, the tail gases from the Stretford unit and Claus plant were routed through the boiler flue gas treating section for further removal of sulfur compounds.

Table 44 compares the SO_2 and particulate ground-level concentrations of the WESCO Project with the Prevention of Significant Deterioration requirements. This table reflects the difficulty that will be experienced in designing coal gasification plants which impact Class I areas where a portion of the increment has already been committed.

The WESCO Project used Best Available Control Technology on coal handling, sulfur recovery, and the boiler flue gas to reduce the emissions to the level shown. Total sulfur dioxide for one plant was 2.34 micrograms per cubic meter. For the four plants, it was 5.46 micrograms per cubic meter. If we were impacting a Class I area, we would not be able to build the WESCO plant if any part of the increment was already used.

Figure 39 illustrates the effect on cost of increasing the percentage of sulfur removed. The cost per pound becomes astronomical as the percentage recovery increases to about 98 percent.

This curve is representative of the cost relationship that exists for all environmental controls. I assume this is the type of curve that EPA is stressing in producing their regulations. In other words, if we start impacting on the area where it costs us millions of dollars to remove very low percentages of contaminants, then the 10 to 20 percent figure that I have mentioned will increase to an uneconomical level.

The gas-to-liquids section of the plant will have insignificant amounts of SO_2 and particulate emissions, since the fuel used in the process heaters will be essentially sulfur-free fuel gas.

Nitrogen oxide emissions are confined to those emissions produced in the combustion of fuel necessary for providing process steam, process heat, and electrical power. Controls on this equipment are dictated by emission regulations, since PSD requirements have not been finalized.

Control of hydrocarbon emissions is accomplished by the use of mechanical seals on pumps and compressors, special care in construction of equipment and piping, and proper selection of valves to ensure minimum leakage through packing. To avoid leaks in piping and equipment, hydrostatic tests are conducted to ensure a watertight system before plant start-up. Welds in critical surfaces are radiographed and magnafluxed to ensure proper metal continuity, thereby avoiding rupture under stress. Where designated by construction codes, heat treating is practiced to relieve internal stresses on welds throughout the complex.

Carbon monoxide emissions are insignificant since minimum amounts of carbon monoxide are vented to the atmosphere. We add a total of 4.95 tons per day of sulfur to the atmosphere, compared to 226.4 tons present in the coal. This low emission rate demonstrates a very high removal efficiency.

Fluor is presently making a significant effort to improve the economics of producing liquids from coal in an environmentally acceptable manner. The objective of this continuing effort will be accomplished by improving designs and providing processing schemes best suited to the client's marketing situation, plant site, and overall economics. We plan to continuously evaluate new processes and processing schemes to provide economical, environmentally acceptable designs for our plants. A part of this effort involves an evaluation of the various licensor processes and processing schemes to determine the best application for a particular project.

A pending agreement on a working arrangement between SASOL and Fluor will provide Fluor clients with access to a large accumulation of knowledge, experience, and technology. This expertise will provide a sound economic and technological base for planning, optimizing, designing, constructing, and operating a complete facility capable of converting coal to transport fuels.

This agreement, coupled with Fluor's management and active participation in the engineering, construction, and start-up of the South African coal-to-liquids complex presently being constructed, will provide our clients and Fluor with a wealth of information on the design and operation of a commercial facility.

Bob Hangebrauck, EPA: From your past experience, could you comment on the optimum size and time to construct on some of the plants that you are looking forward to in the future?

Mr. Thomson: I can't predict an optimum size since it depends upon the site location and the amount of available coal. A plant, to be economical, requires a coal source sufficiently large for operation at the design rate through-

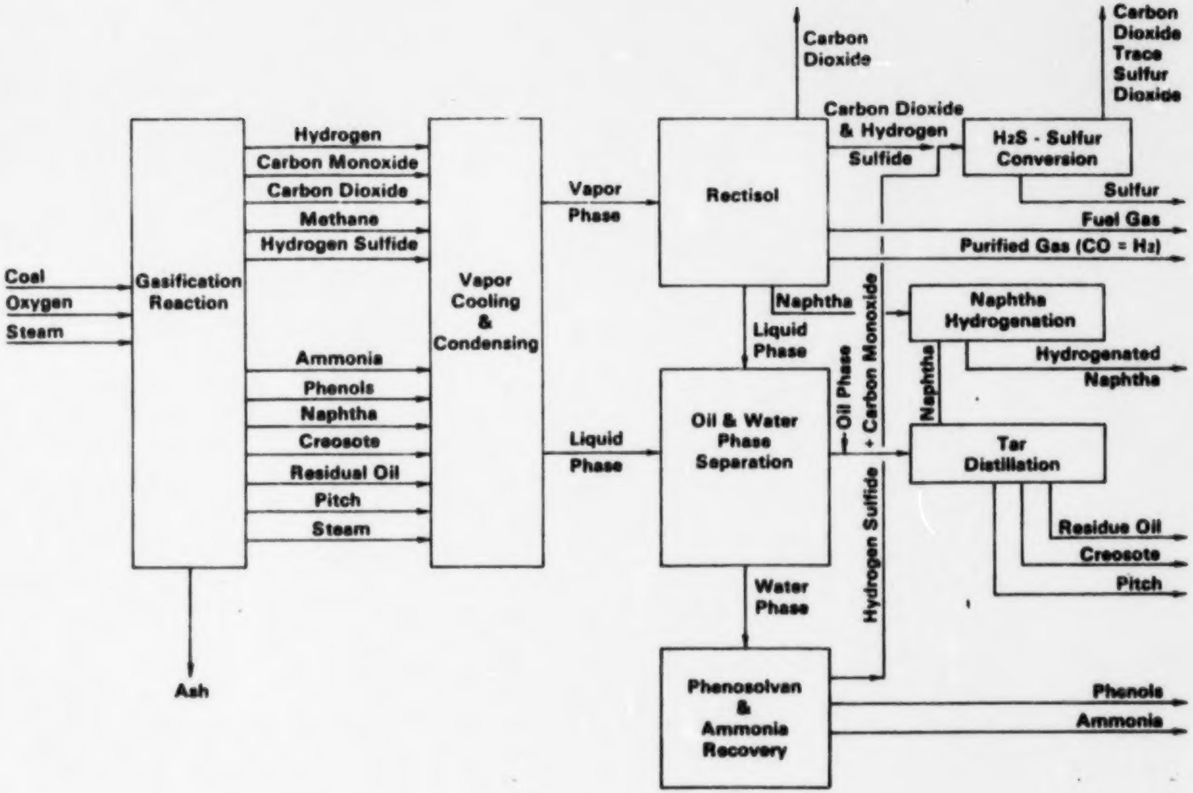
Coal
Oxygen
Steam
Gasification Reaction
Ash
Hydrogen
Carbon Monoxide
Carbon Dioxide
Methane
Hydrogen Sulfide
Ammonia
Phenols
Naphtha
Creosote
Residual Oil
Pitch
Steam
Vapor Cooling & Condensing
Vapor Phase
Liquid Phase
Rectisol
Carbon Dioxide
Carbon Dioxide & Hydrogen Sulfide
H2S - Sulfur Conversion
Carbon Dioxide Trace Sulfur Dioxide
Sulfur
Fuel Gas
Purified Gas (CO = H2)
Naphtha
Liquid Phase
Oil & Water Phase Separation
Oil Phase
+ Carbon Monoxide
Hydrogen Sulfide
Naphtha Hydrogenation
Hydrogenated Naphtha
Naphtha
Tar Distillation
Residue Oil
Creosote
Pitch
Water Phase
Phenosolvan & Ammonia Recovery
Phenols
Ammonia

Figure 36. Block Flow Diagram of Gasification Section

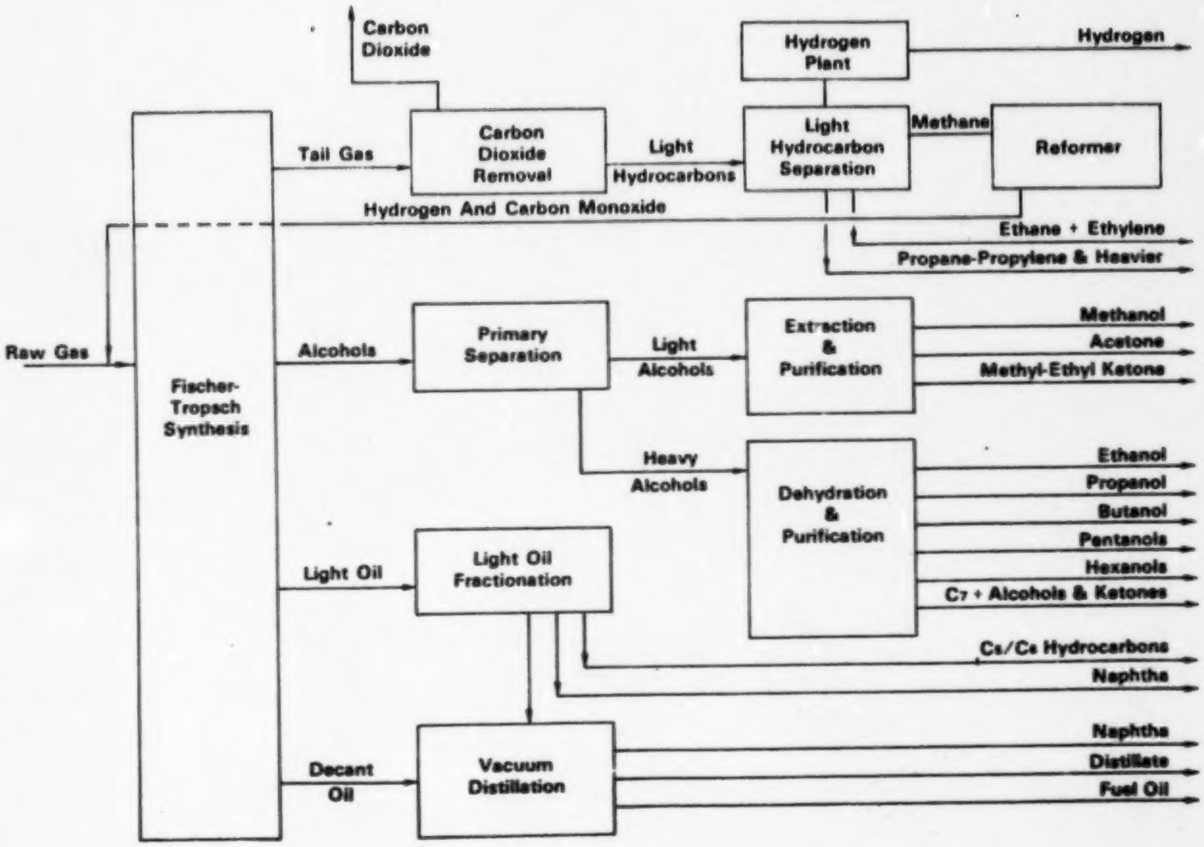
Carbon Dioxide
Hydrogen Plant
Hydrogen
Tail Gas
Carbon Dioxide Removal
Light Hydrocarbons
Light Hydrocarbon Separation
Methane
Reformer
Hydrogen And Carbon Monoxide
Ethane + Ethylene
Propane-Propylene & Heavier
Raw Gas
Fischer-Tropsch Synthesis
Alcohols
Primary Separation
Light Alcohols
Extraction & Purification
Methanol
Acetone
Methyl-Ethyl Ketone
Heavy Alcohols
Dehydration & Purification
Ethanol
Propanol
Butanol
Pentanols
Hexanols
C7 + Alcohols & Ketones
Light Oil
Light Oil Fractionation
C5/C6 Hydrocarbons
Naphtha
Decant Oil
Vacuum Distillation
Naphtha
Distillate
Fuel Oil

Figure 37. Block Flow Diagram of Gas-to-Liquids Section

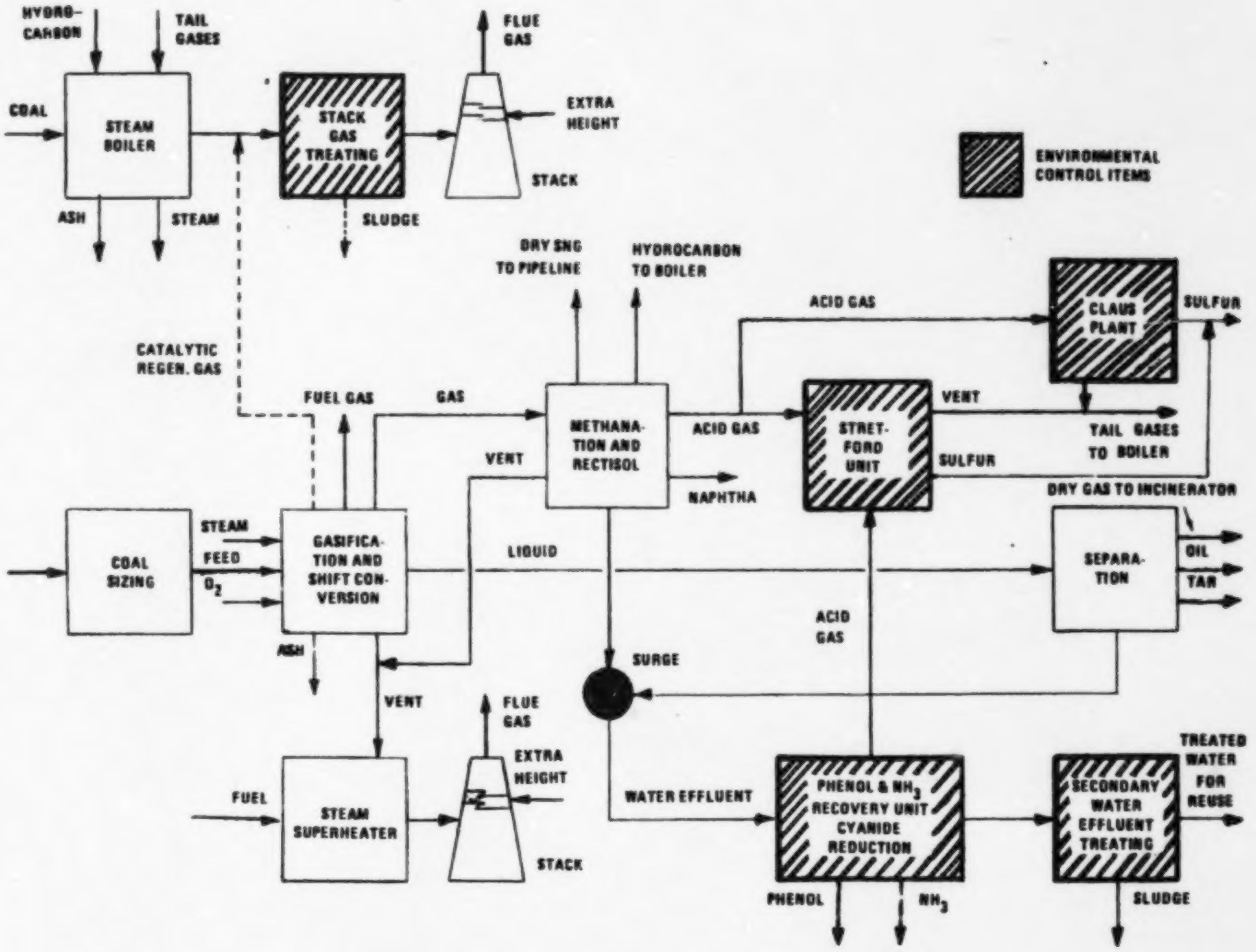
HYDRO-CARBON
TAIL GASES
COAL
STEAM BOILER
ASH
STEAM
STACK GAS TREATING
SLUDGE
FLUE GAS
EXTRA HEIGHT
STACK
ENVIRONMENTAL CONTROL ITEMS
CATALYTIC REGEN. GAS
FUEL GAS
GAS
DRY SNG TO PIPELINE
HYDROCARBON TO BOILER
METHANATION AND RECTISOL
ACID GAS
CLAUS PLANT
SULFUR
VENT
STRETFORD UNIT
TAIL GASES TO BOILER
SULFUR
NAPHTHA
DRY GAS TO INCINERATOR
COAL SIZING
STEAM
FEED
O_2
GASIFICATION AND SHIFT CONVERSION
ASH
LIQUID
SEPARATION
OIL
TAR
ACID GAS
SURGE
VENT
VENT
FLUE GAS
EXTRA HEIGHT
STACK
FUEL
STEAM SUPERHEATER
WATER EFFLUENT
PHENOL & NH_3 RECOVERY UNIT CYANIDE REDUCTION
PHENOL
NH_3
SECONDARY WATER EFFLUENT TREATING
TREATED WATER FOR REUSE
SLUDGE

Figure 38. Diagram of WESCO Project

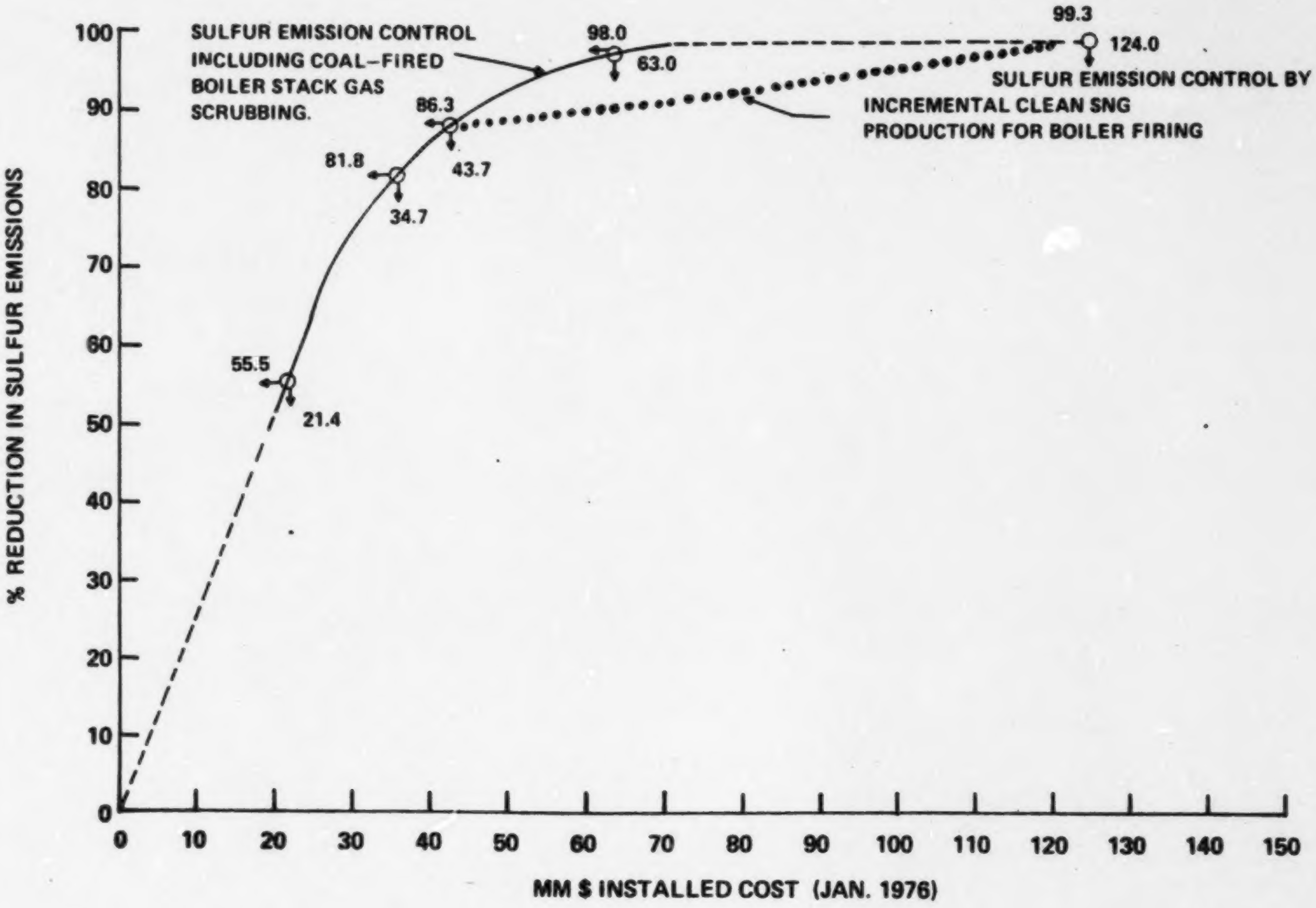

Figure 39. Percent Reduction in Sulfur Emissions vs. Installed Cost

TABLE 44. GROUND-LEVEL CONCENTRATIONS OF WESCO PROJECT

(MICROGRAMS/CUBIC METER)

	WESCO*	
	1 Plant	4 Plants
Sulfur Dioxide	2.34	5.46
Particulates	1.0	1.2

	PSD		
	Class I	Class II	Class III
Sulfur Dioxide	5	91	182
Particulates	10	37	75

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*Information on WESCO Project was obtained from Final Environmental Impact Statement - Volume 1, Prepared by the U.S. Department of the Interior.

out the predetermined payout period. Smaller coal sources may provide economic justification for smaller plant sizes.

Establishing one optimum plant size that is universally applicable is a popular concept but conditions such as plant site, coal cost, environmental considerations, product value, etc., make this impracticable.

Mr. Princiotta: How about the schedule?

Mr. Thomson: Well, I believe the SASOL plant has taken about three years to construct from the time we started the first phase.

Mr. Princiotta: Does that include design?

Mr. Thomson: I might refer that to Barney Groten. What is the contemplated schedule on your project?

Barnet Groten, Texas Eastern Corp.: It's probably closer to four years, which included really opening up a piece of prairie that didn't have anything on it before. That includes the preconstruction activities of building a township and everything else that went with it.

The actual start-up was spread out over about a nine-month period. So, some units are already hot, some others are still being finished. But, call it four years. That's a rough number.

Kelly Janes, EPA: I think I have another question for Barney. When you reviewed the SASOL operations, did you take into consideration all the various by-products it makes and how it might influence the overall profitability of the place? Everybody keeps talking about gasoline, but that system down there is a petrochemical refinery. Have you considered all those special products they put out?

Mr. Groten: As the old joke goes, it's not a problem, it's a challenge.

Yes, there are two features to that process, one of which you just hit on. It turns out a range of materials that can either be worked into gasoline or converted to gasoline. For example, alcohols and oxygenated materials can be run through the Mobil unit to make more gasoline, if that's your pleasure. In other words, they can be dumped in the gasoline pool or they can be marketed separately. The plant also has some flexibility as to how much of these different products are produced within limits.

The answer to the question is, yes, we sure look at the economics within all the groups.

Mr. Thomson: Mr. Groten is not the only client who has investigated marketing a range of products produced from coal liquefaction processes.

Mr. Janes: I wondered because you very seldom hear that the coal conversion unit can provide a multiple array of products. Discussion always seems to center on gasoline.

Every once in a while, they make a comparison between conversion to total hydrocarbons, but you don't hear much discussion of the economic tradeoffs of making gasoline or making special waxes or moving into the polyethylene area.

Mr. Groten: Well, the chemical that is developed is important, which is methane.

In South Africa, the Segunda plant does not have a pipeline network right now which goes back and produces a gasoline which is low in thermal efficiency. In the United States, I would hope that you are flexible enough to use a good, clean fuel when it's made without doing anything to it.

Mr. Princiotta then introduced Daniel Pierce of the Illinois Energy Resources Commission.

Problems Relating to Coal Liquefaction in the State of Illinois: Daniel M. Pierce, Illinois Energy Resources Commission.

As you might have gathered, I am a nontechnical person, a member of the Illinois State Legislature, and Chairman of the Illinois Energy Resources Commission.

I think it's most appropriate that this conference be held at this time, especially under the U.S. EPA auspices, because of the interest of both the federal and state governments in synthetic fuels this week. I don't know what we will have next week. This week you have got a good week.

Seriously, the State of Illinois did show an interest many years ago by authorizing the Coal Development Bonds. We have been looking for ways to spend that money, without much luck so far.

The only construction project actually underway is a fluidized-bed project by Combustion Engineering Co. at Great Lakes Naval Training Station. It seems that the federal government is a little short of cash and the State of Illinois had to come up with $750,000 of our bond money to help the Navy and the Department of Defense construct their heating plant up there at Great Lakes. We hope it's completed before they close the base. We are very optimisitic that it will, but it may be close.

We have been disappointed in other projects. I won't recite the various projects in Illinois, the fluidized-bed projects, and so on and so forth, that the federal, DOE people, or someone has backed out of for one reason or another.

After meeting with some of the people in the White House who are working on the Energy Program, we understand that synfuels are on a fast track. (That is kind of a new term in government, fast track). That means that by 1990, they hope they will have a plant open somewhere. Anyway, that's this week's message.

The Energy Mobilization Board looks like it will pass Congress in pretty much the form the President wanted, not Ribicoff's watered down version that the state and local governments and some environmentalists wanted. It looks like it will come up this year in Congress pretty much in the version Carter proposed.

The Energy Security Corporation, which many of you may not be crazy about, is having more difficulty and may not become law this year, but could very well become law within the next 12 months. This goverment-chartered, independent corporation is modeled on TVA. It is hoped that they will produce 1.75 million barrels per day of oil substitutes. It's easy to see that that's quite a bit of oil substitutes.

In Illinois, we haven't differentiated much between gasification and liquefaction. Even though I am not an engineer, I have an understanding that gasification may be the first stage of liquefaction anyway.

The federal government's new feeling on gasification was evident when the FERC reversed its hearing officer and authorized the construction of the coal gasification plant in North Dakota that American Natural Gas, Tenneco, People's Gas Systems, Columbia Gas System, and others want to build and said that the rate payers should pay for. That decision just came out early this week.

Apparently, that plant at Beulah, North Dakota, may go ahead unless the developers delay it because of high interest costs or other problems. That's the first sign that the attitude has been changing in Washington.

As to the environmental considerations, the federal government often makes exceptions for itself when it comes to obeying federal environmental rules. The President's office has put out a publication entitled "The President's Program for the United States Energy Security: The Energy Security Corporation." In it, they point out that the Energy Security Corporation shall be exempt from requirements of the National Environmental Policy Act only for those decisions of the ESC related to broad program definition. But at least they are exempt in that category. However, "The Energy Security Corporation shall be obligated to assess the environmental impact of such generic or programmatic decisions in annual reports to the Congress," whatever that means.

So, on the fast track, we may see some short cuts -- we may see some shortcuts on the environmental regulations that myself and others have helped create in this country.

We in Illinois have long felt that we are the best state for coal liquefaction or gasification plants. What do we have? We have the coal, probably the greatest supply of high-sulfur coal and high-Btu coal in the country, compared to some of the Midwestern coal and Western coal. We have water -- Mississippi River water and other water -- available for the gasification process. We have transportation facilities, probably second to none, both common carrier and specialized pipelines, rail, barge, and so on. We have nearby markets, consumer markets and industrial markets for the product of the liquefaction.

We recently authorized $18 million of our coal development funds for a coal gasification project being developed by Allis-Chalmers, the Kiln Gas Project at the Wood River Plant. Illinois Power Company and a consortium of about 15 or 20 electric utilities around the country, from Baltimore Gas and Electric on the east and Oklahoma Electric Public Service on the west, are helping to fund this consortium along with Allis-Chalmers. The long-term objective is to make a gasifier out of those kilns that are used now in their iron ore work and produce a low-Btu natural gas to be fed into the existing steam boiler plant of Illinois Power at Wood River on a demonstration-plant basis.

Their target is not only utility gasifiers but also those in industry, perhaps eventually upgrading the product for the middle-Btu market. We have agreed to fund that $18 million. The reason that is moving ahead is that they never went to DOE for funding. On their $100 million project, they are still a few million dollars short and they hope to bring in a few more electric utilities. Two or three have joined this year. They will get that under way sometime next year. Commonwealth Edison, so far, has shown no interest in it, but most of the other electric utilities in the East and Midwest have joined in that consortium.

The Cumberland Energy Plex is a total concept energy facility planned for southeastern Illinois. It gets the name Cumberland because it is located in Cumberland County, although it could be located in numerous other counties in southern Illinois and southern Indiana with the same kind of set-up.

We are looking forward to creating 4,000 new jobs, constructing four new coal mines, and supplying 4,000 tons of coal per day to power plants. The Energy Plex will also produce SNG and ammonia. The power plants would generate 1,500 megawatts of electricity. The SNG plants would feed 250 million cubic feet of gas into the existing natural gas pipelines. The ammonia plants would produce 3,500 tons per day of anhydrous ammonia for Illinois use and feed into the pipeline for use by neighboring states.

More interesting to us, the carbon dioxide from the ammonia and the SNG plants will be used as an injective to recover up to 80,000 barrels of crude oil per day from depleted oil fields in Illinois by way of tertiary recovery. The oil fields studied are in Franklin and Hamilton Counties, which are adjacent to Cumberland County, but other oil fields in that area would be amenable to tertiary oil recovery.

The reject waste heat from the coal-consuming plants could be used for food production in greenhouses or fishponds or for food processing such as soybean or cornmeal operations.

We feel that the environmental impact of using coal in these plants would be only one-half of that of the coal which is used entirely for generating electricity.

This would be a $4 billion project over a 15-year period, with private investment as well as government investment. The study is being conducted by SRI International, Menlo Park, California, under a Department of Energy contract. They are continuing to refine the economic estimates for the Cumberland Energy Plex. Of course, we in Illinois are excited about this total-concept synthetic fuel program. So, when you see reference to the Cumberland Energy Plex, you can act knowledgeable and know that it's planned for somewhere in southern Illinois.

While we're on the fast track and while we still have some coal bond money left, I would hope that those of you -- and I see you are from the major companies in this field in the United States -- would consider Illinois in working with the Institute for Natural Resources and the Illinois Energy Resources Commission.

We have the bond money available to match funds with you. Ordinarily, they will not have to be repaid to us.

We are working for commercialization of high-sulfur Illinois coal, because we have been quite discouraged with the attitude of Commonwealth Edison and other companies toward direct burning. Commonwealth Edison has refused to adopt scrubbers and is importing Western coal into our Illinois coal area.

I might say, however, that Central Illinois Public Service is in the process of opening a new plant in Newton, Illinois, where a double alkali scrubber will be used with high-sulfur Illinois coal. The scrubber accounts for over $100 million of the cost of a $400 million plant. You throw the lake in that goes with the scrubber and the price goes to $140 million, for which you get a nice little sulfur chemical plant known as the double alkali scrubber and everything that goes along with it. This is expensive technology. We are confident it will work. It's worked on a smaller scale in other places.

We are contemplating now using that plant as a pilot for commercialization for industrial and other uses, perhaps making some of our bond money available for commercialization experiments at Newton with the double alkali plant for use in other places. That's not direct liquefaction but, again, as you know from your lecture so far, gasification is a procreator in many cases of liquefaction. You can't study one without the other.

That's our attitude here in Illinois. We want to cooperate with the federal government now that we have them on the fast track. Only one thing scares me about them. We fear a little bit that synthetic fuels are this week's pet, because of the problem at Three Mile Island with nuclear power. When people start writing papers about acid rain, the President will be reduced to talking about gasohol. I heard the question down at the town meeting in Dolton, Illinois. Someone asked the President about synthetic fuels and substitute fuels. He started talking about cars that get 27 miles per gallon and discussed conservation and solar energy, a Jerry Brown-type talk. Then he went on to become a great advocate of gasohol.

Those of us from Nebraska, Iowa, and Illinois, at least, are glad to hear the federal government, especially its Chief Executive, talking about gasohol, which they laughed at a year or two ago. I say this as a member of the President's party, the party that nominated him and may be for him again.

But, it's good to have a program. I didn't notice in the President's remarks as strong a commitment to synthetic fuels in the political-type framework as in the legislation introduced in Congress. I think we have to tell the people that there is no single solution to our energy problem, that nuclear energy is part of the solution, that direct burning of coal is part of the solution, that gasificaton and liquefaction are part of the solution, and that passive solar will be a small part but active solar will be an important part of the solution by the year 2000. All these and conservation, of course, are part of the solution, and until our public figures are willing to state that to the people, I think we are fooling them.

In the Illinois Energy Resources Commission, we have tried to be open to all methods, realizing that there is hardly an energy-creating technology that doesn't have environmental problems, that we don't have to put into perspective, weigh against the objectives, and balance the pluses and minuses.

Sid Thomson, Fluor Corporation: You had a low-Btu gas turbine operation with Commonwealth Edison that was discontinued. Is there a possibility that this project will be revived?

Mr. Pierce: I guess not. They know it works. They called it Powerton. Commonwealth Edison withdrew any further interest in Powerton and DOE didn't give them all the cooperation they could have.

But the high-Btu gas project in Illinois is still alive. Northern Illinois Gas, People's Gas, North Shore Gas, and other downstate utilities have a project in Perry County which is called the Illinois Coal Gasification Group. The federal government has funded that in the planning stage as well as a Conoco project competing in Ohio. It's always been felt that the feds leaned a little bit toward the Conoco Project in Ohio. I don't know whether that's political or what. Maybe it's because Ohio utilities have less gas available than Illinois and they may need it more.

At any rate, we are trying to encourage the federal government to go ahead on both of these concepts. So far, they have funded both in the planning stage, but the money in the budget is only for one of those. They are funded to April 1980. That project, therefore, is still alive, the Illinois Coal Gasification Group High-Btu Project in Perry County.

Mr. Princiotta: To sum up this forum, I have attempted to lay out five questions that I think are pretty critical, to EPA at least, in this general area. I would like to hit them one by one, get your feedback, particularly those of you in industry who don't have a proprietary process, although we are interested in all of them. The aim is to help us in EPA to do a more intelligent job in preparing our guidance documents and control technology standards.

One of our major questions to industry particularly deals with your reaction to EPA's plans for these guidance documents for the control technology-based regulations.

We talked about trying to have these pollution control guidance documents released in 1981. In some cases, they might be able to get technology-based regulations out as soon as 1982, although most likely it will be several years thereafter. We would like to get your opinion of the timing of that process and whether or not you look at the guidance document as a pain the rear or something that has a connection with your efforts and can be helpful to you.

I would also like some recommendations, particularly from Parsons, Fluor, and Texas Eastern Transmission Company, as to how we should set up priorities in terms of your technology-based standards-setting activities. Which of these liquefaction technologies appear to be coming on-stream the soonest? Which ones, in your view, will be most widely commercialized and, therefore, will have the greatest potential environmental impact?

We also would like your advice as to whether it would be reasonable, helpful, and fruitful to expand the technology guidance document, which primarily addresses air, water, and solid waste issues, to include those product handling issues that may be ultimately controlled by the Toxic Substances Control Act.

We would also like to ask each of you for any information that you can send to us that would shed light on the cost of control technology. You may recall I started without my chin with some pretty low estimates on the capital cost requirements for coal. On the Lurgi gasifier, I quoted a 5 percent number and a 10 percent number on operating cost. I was challenged by several of you in that area. We would like you to please supply the supporting information, particularly those of you who have information on honest-to-goodness designs of plants. We will even be happy to receive information on gasification plants. I notice there is more action in the designing phase, at least, for gasification than liquefaction. We want to be corrected if our numbers are astray.

We would also like to get some of your input and suggestions on how we can improve our communication with industry as we move along this regulatory path. As many of you know, three are already built into our air, water, and solid waste regulation processes certain points where we allow for formal comment on these regulations by industry and any other interested parties.

I personally think that it might be fruitful for us to get industry involvement earlier on rather than after many of our thoughts on the standards are fairly well crystallized. It would be more convenient to change early in the regulatory path than later.

Finally, this is not so much a question as a plea. We would like to ask those of you in the liquefaction business to cooperate with our agency so that we can get access to your plant, so that we can get access to your data, so that in some cases, we could cooperate to generate and analyze the data, that essentially we are praying for cooperation rather than confrontation between our agency and the industry.

I wonder if we could address the first of those questions: What is your reaction to our regulatory plans, the guidance documents that we described, and ultimately, the pathology-based regulations which are in the early stages of development?

D.M. Jackson, Gulf Minerals: DOE has a schedule starting the SRC demo plant in 1984. I understand the draft environmental statements will be submitted by the first quarter of next year, which obviously is going to be before you will have any guidelines, based on your schedule. On what basis are you going to try to review that permit when you haven't even formulated the guidelines?

Conversely, I understand that it is DOE's plant and that it is viewed as kind of national experiment in technology demonstration and in addressing institutional factors. It seems to me that perhaps EPA ought to view that plant and plants like it as experiments-as-data-base resources, in fact, for dealing with the standards-setting issue. How is that consistent with your concept of guidelines which are neither in time with the demos or too early for the result of the experiment?

Mr. Princiotta: I think you are right. I think you are pointing out one of our challenges. We are not going to pass very early demonstration plants, certainly not with our technology-based standards. There will probably be several plants that will be looking for permits before 1981.

No, there won't be any guidelines. The Regions will have to do their own thing, make determinations based on BACT and evaluate applications on available information which, admittedly, is pretty sparse.

In fact, Terry, I guess you had to to this recently in the case of the oil shale permit issue. You had to issue what -- two permits?

Mr. Thoem: Four.

Mr. Princiotta: Four permits on oil shale facilities without benefit of the guidance document and any technology-based standards. I think that was done to everybody's satisfaction, as best I can tell. In fact, we were even complimented by an environmental group, which may be unprecedented in the annals of permitting.

In response to the second part of your statement, I think we are very interested in working with you and DOE, which is one of the major sponsors in getting as much data as we can from your plants. Obviously, it will not be in time to impact the very first guidance document. We hope it will be in time to influence the technology-based standards. It depends upon when it gets composed.

There is a school of thought within EPA that says that we should not force-fit technology-based standards. We should not come up with them until we get some full-scale or near full-scale module or administration plant operating experience. This would, of course, delay the standards, by and large, until the late 1980s. In that interim period, we would just have the guidance document and whatever other source material may be available. It is an option that some are proposing within our agency right now. No final decisions have been made.

Norbert Jaworski, EPA: Frank, you say guidance document. That should be plural. There will be a sequence of documents as we get more data updated.

So, in summary, as designers, we would feel much more comfortable with a stable and firm set of guidelines right now.

Mr. Princiotta: Let me ask you this question. Let's say we have, right now, a control technology guidance document for SASOL or Fischer-Tropsch liquefaction technology, and let us say we specified in pretty much detail what kind of controls we thought appropriate for all the air, water, and solid waste problems. We concerned ourselves not only with criteria pollutants but suspected carcinogens. We told you how to go about lining a pond, perhaps, for the waste disposal problem. We got pretty specific as far as controls are concerned, some of which may not carry the weight of law. Is it your feeling that the industry would use that as specifications in their design of a plant or would they look for lower-cost alternatives? Maybe they would say, "Well, which of these is legally binding? I'll put that in and forget about everything else."

What would your company's reaction be on that?

Mr. O'Hara: Well, it would be a significant input to the decision process, it would certainly be taken into account.

Mr. Princiotta: If the control cost were not in your company's and in your client's opinion excessive, do you suspect they would be incorporated?

Mr. O'Hara: It would be an input, very definite input.

Dale Denny, EPA: How would the permit writing people use guidance documents?

Mr. Princiotta: It would be on a case-by-case basis. Terry, any thoughts about how Region VIII would handle a case in which you had this document in hand and somebody came in with a permit request, NPDES, PSD, whatever?

Mr. Thoem: We would use it really as a basis for writing the permit. We would look at it and try to assess how accurate the data were and use it as the guide. Then, if a particular project varied much from the norm, we would decide on a case-by-case basis.

One other thought I might share is that some of the second generation are going more to the module and scale-up approach. Questions are being asked about what guidance we can offer in terms of control technology and emissions limits and so on. It's difficult for us to write a permit because the environmental data isn't there. So, it's kind of a chicken-and-egg situation.

Mr. Princiotta: That's another issue. There are two schools of thought on that. One says that once the control technology-based regulations are promulgated and given to the industry, they should immediately supersede the given guidance document.

Of course, let's face it, the air, water, and waste regulations will not all come out at the same time. So, portions of the guidance document might still be relevant even when, let's say, a New Source Performance Standard has been proposed. We may be dealing with the toxic product question for which we might not have regulations for quite a while.

Mr. Thomson: I believe air emission controls will be determined by the PSD requirements. Once the PSD increments are satisfied, especially if a Class I area is impacted, BACT and NSPS regulations will be secondary. That is my candid opinion.

Mr. Princiotta: Keep in mind that the PSD, as of now, applies only to SO_2 and particulates, which are of minor importance in the overall scheme of things from synthetic fuel plants. We have an array of carcinogens to worry about, we have possibly major water contamination problems, we have water, solid waste, and hazardous waste disposal problems. I don't think PSD is the answer to all our problems.

Mr. Thomson: All those are potentials. Most of them can be contained.

Mr. Princiotta: Great. From a siting point of view, that's going to be critical. There is no question about it.

I am wearing strictly an environmental hat right now, my own personal hat. I don't think in the big scheme of things that these are overridingly important. There are many other important environmental problems, some of which are not even currently regulated at all.

Jim O'Hara, Parsons: My reaction as a designer in looking at some of the economics is that I can do nothing but encourage getting at least your stable set of regulations or guidelines as early as possible.

Take a look at the problems of permitting in the nuclear industry as costs grow. Among the more difficult things to me are the areas where neither the designer nor, let's say, the process company knows what will happen. These are complex facilities. If you are in an advanced design stage and you are making changes, they interface with a number of parts of the plants, particularly if you interface with utility systems. It can stretch out schedules and, therefore, costs.

On the oil shale permits, we approached it on a conditional basis. In looking at those first plans we made our best guess as to what the requirements ought to be, recognizing that we will get more data and then the requirements for that larger plant may be quite different than in that first phase.

Mr. Princiotta: That addresses the subject of the desirability of a stable array of environmental goals. I think we all agree that's desirable, but it implies that we know a lot more about some of these environmental problems that we really do.

I think I can speak at least for the R&D portion of EPA in saying that we will do our very best to maximize stability and we won't react until we get some pretty sound data. But I think regulations and guidance documents do have to vary as the data change.

Mr. Thomson: The cost of meeting reasonable environmental regulations is much less significant than the costs due to delays in obtaining construction and operating permits. I believe most companies are willing to accept the cost of reasonable environmental controls.

Mr. Princiotta: Particularly if you feel it's not going to change.

Mr. Thomson: True, changes contribute significantly to delays.

Mr. Princiotta: I agree with that. That's why I am kind of hot on these guidance documents. I think that we can make a strong case, for example, with the environmental community, that this is our best guess. It is the very best that can be done with these technologies. They live up to our recommendations, they put it in.

I think you would have a pretty strong case for any unreasonable demands placed upon you by some of the less rational of our American environmentalists.

Mr. Denny: I think they are saying that once you get a permit to build your pilot plant unit or your prototype unit or whatever it is, the requirements stay fixed.

Mr. Princiotta: No. We heard that water permits were either five years or ten years for New Source Performance Standards, and PSD was for life of the plant. But your point is partially correct. For those permits that are permanent, once you get them, you have got them forever and ever.

Well, of course, there are exceptions there, too. I guess the SIPs (State Implementation Plans) could conceivably be changed and that would necessitate a change in control.

I have a hunch this is going to be a very difficult one because of the sensitive nature of the subject. But I think we would like your thoughts on which of these liquefaction technologies seem to be the most commercially important and imminent, so we can adjust our resources accordingly. This is particularly important for the standards-setting offices, which have very limited resources and want to put the money where they are liable to get the most bang.

I realize this is speculative and sensitive. Maybe the way to start off is to tell you my impressions or my prejudices and ask you to shoot them down. Assuming we have a security corporation incentive, I am getting the message that particularly the Fischer-Tropsch technology may very well be the first commercially offered and ultimately constructed facility. I also sense that perhaps the Mobil variation is also imminent. I sense that the direct coal liquefaction processes are much farther down the line -- five years, or perhaps even longer, from where the indirect processes are.

I have not heard any overriding arguments for direct coal liquefaction processes other than that they may be attractive on a given application. But, I haven't heard anybody argue that they are necessarily cheaper, more energy efficient, or produce better products.

Mr. Weekman: We have a laboratory in miniature in New Zealand coming up because SASOL was being considered there also, along with their technology.

Mr. Princiotta: Side by side?

Mr. Weekman: Yes.

Mr. Princiotta: That would be an interesting comparison.

Other than the DOE-sponsored demonstration plants, have we heard about any firm commitments to a commercial coal liquefaction plant? I don't think we have. I guess we are all speculating as to what the situation might be. I can't believe our direct liquefaction people will let my statements go unchallenged.

Mr. Groten: To answer both of your questions, no, you haven't heard any commercial commitments because everybody is waiting to see what will come down off the hill from the Energy Security Corporation Bill.

The second part of this addresses your earlier question of which technology is going to come first. The impression we get now is that one of the functions of the Synthetic Fuels Corporation will be to mix technologies. At least at this point, it's not going to be one where everybody is free to pick whatever they want, and it very well may turn out that everybody will take the same thing.

There's going to be some forced mixing. So, you are going to get a spread of technologies in that -- call it that -- and ten after a -- I think it's a two-year or three or five-year period or something like that -- after the expenditure of the 20 -- 20 to 30 minimum product comes down as FSC is supposed to come up with a plan for longer range conservative development of the entire industry.

Mr. Princiotta: Yes, I sense that trend, but there is another school of thought about the Energy Security Corporation. I think what the President had in mind, originally, was not so much that approach, maybe less spread the wealth. Actually, what you could call it is a demonstration program.

The original goal was to reduce import production by a certain amount by a certain date with the cheapest technology available. There is still a residue of that opinion in the Congress, as best I can tell. If it truly is the cheapest technology that's here now, I think you will get a different mix than you will if your goal is to demonstrate oil as the probable viable technology and later on see what happens. I realize this is speculation.

So, I guess what we are saying is that the best way is to monitor the Congress very carefully. Maybe that's the bottom line of it all.

Any other thoughts about the likely mix or what the future of coal liquefaction is?

Mr. O'Hara: I'd like to comment on just one part of it. Certainly my opinion for everything we have seen is that the direct liquefaction has a potential that will show a higher thermal efficiency than the indirect, for whatever value that might have in the total economics, just by the inherent nature of synthesis.

Mr. Princiotta: Is 62 percent thermal efficiency a correct figure for the Mobil process?

Mr. Weekman: Yes, from coal.

Mr. Princiotta: What are the direct liquefaction processes getting, 65 maybe? It seems like the same order.

Mr. O'Hara: Again, it depends upon the plan. We can see a potential for it being in the 70s. This becomes a series of cost-benefit analyses in working our way out. To summarize, I think in the first-time look at it, using some of the procedures we use, what I will call refinery technique, it would come out in the low 60s.

You can see by sequencing in a whole series of these, looking at an energy machine, you can work your way up. The final balance becomes, of course, a question of judgment. But, potentially, you can, in essence, equal up.

Mr. Weekman: Jim, I have to be careful, though, with where you are heading with the final product. If you are going to produce a good boiler fuel or turbine fuel, then the thermal efficiency might be higher. If you structure all the way to a very high premium gasoline and high diesel fuel, then you incorporate some inefficiencies in reaching those product equivalents.

Mr. Princiotta: So, it will equal hydrogen. It all boils down to the amount of hydrogen you need to get the product. I think that will be a big equalizer.

Mr. O'Hara: I agree.

Dr. Loran: There is need for both. You need indirect if you want gasoline and that type of product. If you want to supply the utility companies that are presently using oil-burning power plants that cannot be converted to coal, then you could build direct liquefaction plants to give them the fuel oil.

Mr. Princiotta: But that's a pretty small market, the 1990s.

Dr. Loran: I don't have the figures, but the use is there.

Mr. Princiotta: Okay. Why don't we move on to the question of product handling?

Clearly, we are all aware of some of the Ames Tests and some of the other toxicity tests that have indicated that coal liquefaction products, particularly direct liquefaction products and I think some of the oil shale products as well, are relatively toxic, compared to some of the petroleum products.

Does it make sense, therefore, for us in our guidance document to make some suggestions about appropriate handling procedures or are we getting out of the appropriate subject area for a document of that kind?

D.M. Jackson, Gulf Minerals: My only comment is that if you feel you have a pretty good and thorough understanding of the nature of the product, then it may be appropriate. If you don't know, and I suspect that's the case, then perhaps you should consider cooperating with DOE on additional work to develop data.

Mr. Princiotta: We are doing that. Are you suggesting then that it's too early for us to discuss?

Mr. Jackson: I'm suggesting that programs addressing that really aren't very far along. A guidance document within 15 months probably won't have much more significant data.

Mr. Princiotta: I would tend to agree with that but I think that the same argument could be used for everything that's going to be in the guidance document. We are not going to be able to generate too much new data.

Mr. Jackson: We are not going to generate too much new product to handle for at least several years.

Mr. Princiotta: So we can wait. From your point of view, it might be helpful.

Mr. Jackson: Yes.

Mr. Princiotta: Somebody indicated that if we did put these practices in the guidance document and you did fulfill the recommendations in these documents, that a strong case would be made that you are being environmentally responsible.

So, conceivably it could be a plus. From an environmental point of view, you could say that we are putting on suspenders when we don't really know whether a belt is good enough. It might be overkill, but if the recommended controls are not overly expensive or troublesome to the developers, it might be worthwhile.

Mr. Denny: I think you might want to consider OSHA's reaction to that kind of input too. They have regulatory authority.

Mr. Princiotta: That is a good point.

There is another possibility which I will just mention in passing. These documents could include not only air, water, solid waste emissions, and product handling, but actually the occupational hazards in the plant itself. That conceivably could be done. Of course, it would mean interacting with at least one other agency. As you know confusion as to the number of organizations involved could become a problem.

Kelly Janes, EPA: These two gentlemen here have been deeply involved in SASOL. They know more about that plant than anybody else. Do they conceive that we could come up with some kind of regulation that is going to surprise us?

Mr. Princiotta: You are referring not to just products but air or any new regulations?

Mr. Janes: The total one. They certainly understand that EPA intends to protect health and the ecological system, could they foresee that we could have a requirement that would really upset that product design?

Mr. Princiotta: I guess it depends on how rational they think we are. I won't estimate a comment on that.

Mr. Thomson: I will make a comment. In working with the EPA, I have not found them as irrational as most people predict. I recognize the difficulty they face in developing regulations that are meaningful and still satisfy everyone concerned. I welcome the opportunity to discuss regulatory problems and supply industrial input.

Regarding health effects of coal liquefaction plants, OSHA engaged a contractor to investigate SASOL medical records and interview workers to determine the carcinogenic effect of emitted compounds. No evidence of cancer was found among the workers. Additionally, the investigator was unable to elicit a single case which conformed with clinical symptoms one might associate with chronic lung disease. This investigation indicates that synfuels production does not create the health hazards that are continuously being predicted by negatively thinking individuals.

In regard to guidance documents, I firmly believe there are sufficient regulations presently in existence to cover coal liquefaction projects. If EPA plans to prepare guidance documents, I suggest issuing the documents as they are prepared instead of waiting until the entire set is completed. This will allow us to compare guidance documents to similar regulations on other plants so that we may anticipate requirements of the guidance documents to be issued in the future.

Mr. Princiotta: Rather than all at once?

Mr. Thomson: Rather than wait and try to issue them all at once.

Mr. Hangebrauck: Frank, another approach that you might consider in some of the areas where we feel there is some weakness in the data base is to put in some kind of option to define what the possibilities are that may be addressed and then, depending on the decisions involved in a particular case, they could be selected arbitrarily.

Mr. Princiotta: Yes, in fact that gets into another important sub-issue: the degree of specificity that we should have in these guidance documents. One school of thought says they should read like standards, which are, of course very specific.

Another school of thought says they should just mention the kinds of controls that might be appropriate and let it go at that.

Any thoughts along these lines?

Mr. Groten: Yes, that is a wrap-up of my thoughts. I guess the main plea I would like to make is that recognition be given to the fact that these are different processes, they have different histories, and they have to be treated differently.

Mr. Princiotta: And, therefore, flexibility would be appropriate?

Mr. Groten: Yes, something that's a blanket for the worst possible case could do a very grave injustice to the entire industry in terms of the United States developing something like this.

One further comment. They had a long history in South Africa of monitoring this plant and, just so that nobody is misunderstanding what goes on down there, they have a very rigorously run plant, both by the plant management and by the State Regulatory Authority, which is their equivalent of EPA and OSHA and everything else.

Their records have been thrown open, or at least were once, as Sid mentioned. There was nothing that could be found that would even remotely raise the question of some sort of chronic effects in terms of carcinogenicity, lung damage, and hearing damage.

In some of the other areas, such as ash handling, the new plants are being designed for zero discharge. That's something that is totally conceivable.

Mr. Princiotta: By the way, the existing plants, as I understand it, did not have much in the way of controls. For example, there was no sulfur removal technology and not much water treatment, either. Is that accurate?

Mr. Thomson: No, they have quite an extensive water treatment.

Mr. Princiotta: Do they have sulfur control at all?

Mr. Thomson: It's dispersion.

Mr. Princiotta: They oxidize it with sulfur dioxide, I suppose, as opposed to hydrogen sulfide.

Mr. Thomson: Yes.

Mr. Groten: Particulates are the one glaring omission on the first plan - very, very nominal control.

Mr. Thomson: Like the old coal mines.

Mr. Groten: Right. The new plan, of course, is designed to control that. Again, it was not because of any internal goal to control particulates, it's just simply that the regulations were made on them and they complied. It is very analogous to the situation here.

Environmentally current thinking also considers the socioeconomic impact of building a plant that size. The current population of the construction center is around 25,000 people. So, they have been moved into a clean grassroots site. I think the last time I saw the police station there, it was a mobile van; and they had two cops. Aside from the occasional Saturday night violence, which was very nominal, the impact of moving into a clean area, starting up this plant, and getting out again is really about as mild as you could imagine.

The original plant, which also 20 years ago was started on a green field site, is a very nice little town right at the foot of the ash pile. You can stand on top of the ash pile and the biggest problem you might have standing up there is seeing through the trees that are growing on it. Looking down, that town is absolutely clean.

What I am saying is that be as critical as you can in terms of analytical data. The results of 20 years of cumulative effect are pretty obvious to anyone who wants to look with unbiased eyes.

Mr. Princiotta: As you may know, EPA has had difficulty in getting to do much with the SASOL plant because of the political problems.

Bob, what is the status now? Are we getting access?

Mr. Hangebrauck: I think we are still trying with one of our contractors here. We have been trying through one of our contractors to get around the problems that you mentioned, the State Department and otherwise.

Mr. Princiotta: Can Fluor or Parsons or anybody else help us get access? We have to go government to government.

Mr. Hangebrauck: I think that's the problem.

Mr. Princiotta: For political reasons.

Mr. Hangebrauck: They would like us to sign an agreement directly, government to government.

Mr. Princiotta: And our government says no good. So we can play the game through contractors. We would appreciate any thoughts about how we might be able to finesse that problem through a contractor.

Mr. Janes: That's right, we have that problem. Although, we have a very good relationship with them, we were progressing toward an agreement to get this type of data, but the State Department stepped into it.

Mr. Princiotta: And said no.

Mr. Groten: So why don't they get on the energy bandwagon like all the other departments?

Mr. Janes: DOE has the same problem.

Mr. Princiotta: The politics are pretty hot and heavy as everybody knows.

Mr. Janes: I don't think our money can compare with DOE's potential. SASOL might be less interested in working with EPA than with some of the others, but I agree with your plea.

Mr. Princiotta: I'd like to make a suggestion. Possibly one of you who do have connections can act as a subcontractor to one of our major contractors. That might be one of the routes to get into that. I am talking off the top of my head here.

Mr. Thomson: I think you should recognize that we have similar political problems.

Mr. Princiotta: You probably do. What do you do, let the State Department worry about it?

Mr. Thomson: That's right.

Mr. Princiotta: Well, okay. We can't solve that problem here. Unfortunately, we have not had the access to that experience, which is obviously very relevant.

Can we move on? This is a very fast one. This is more or less a plea. If anybody has cost data on control for liquefaction and, for that matter, gasification plants, particularly at the commercial size, we would all love to get our hands on it.

The gentleman from Parsons, Mr. O'Hara, has already given me a slew of reports in that area. Fluor could do the same or, I think, Exxon gave us some information on their EDS process. We are trying to compile all these so we can keep informed as to what's out there in the way of cost data.

Let me go on then. I think this is the last subject, other than my final plea again, would be any of your thoughts on how we could better communicate with the coal liquefaction industry during our regulatory process. I think the earlier we communicate, the better. This is the first step along the line. Any other thoughts about how we could keep these lines of communication open or improved?

Mr. Thomson: You could assist us by sending notifications when you have meetings where you are discussing regulations as they relate to coal liquefaction and gasification.

Mr. Princiotta: Okay. We have not really had an open discussion. All the discussions, quite frankly, other than what you heard today and yesterday, have all been closed, very early strategizing sessions.

That's not to say that maybe we shouldn't meet four or five months from now and tell you our more current thinking, and get your reactions to that. Perhaps this group should not be ad hoc, it should be set up on a continuing basis. We are really open to suggestions here.

Mr. Thomson: I am personally concerned, and I am sure my company is concerned, about the effect of regulations on plant costs and delays. This is especially important when dealing with projects which have extended engineering and construction schedules. Anything we can do to expedite the promulgation of reasonable regulations and rapid permitting activities can greatly enhance our energy efforts.

Mr. Princiotta: So, you would be in favor of periodic meetings?

Mr. Thomson: That's right.

Mr. Princiotta: Is there any trade group that represents the coal liquefaction industry? Does API have a sub-group on coal liquefaction, for example? Is there any one entity that would speak for this emerging industry?

Mr. Hangebrauck: No one that everyone else would agree is the spokesman.

Mr. Princiotta: That would make life a lot easier for us.

Mr. Denny: Are you getting those goals together before you get the control technique guidance documents?

Mr. Princiotta: Yes, I think that would make sense. Periodic meetings could be held along the time line that we set up, let's say, to produce various coal liquefaction documents. You might want to reconvene this meeting, perhaps expand it a bit to make sure we didn't miss any important company and get your input as we go along.

Any thoughts on that? Does that sound reasonable?

Mr. Janes: Frank, would they review the data we're getting?

Mr. Princiotta: That's another possibility. Again, I'm hitting you cold on a lot of these questions. We would love to get your comments in the mail on this and we are open. I think we are going to try to design our time lines so that we do hit the rap with industry.

On the one hand, if we have too much interaction, it might eat up too much of our time or we can be accused of being in bed with industry -- that's the negative end. On the other hand, you guys have the data, I think you'll agree that if our guidance documents are credible and reasonable you are more likely to incorporate them into the design where they are not legally binding. On that end, it is more to our benefit.

Okay. With that, the last plea: We would appreciate your cooperation with us on access to your plants, letting us see your data, working with us jointly and generating data.

Let me just say it's been a pleasure to help emcee this event over the last two days and thanks for your attention and cooperation.

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